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February 5, 2014

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VIAHAND DELIVERY
Alisa Bentley, Secretary
Delaware Public Service Commission
Cannon Building, Suite 100
861 Silver Lake Boulevard
Dover, DE 19904

Re: Docket No. 13-115 – Delmarva Power & Light Company's Post Hearing Reply Brief

Dear Secretary Bentley:

Enclosed please an original and ten (10) copies of Delmarva Power & Light Company's Post Hearing Reply Brief being submitted in the above-referenced docket.

Should you have any questions or require any additional information, please do not hesitate to contact me.

Very truly yours,

Pamela J. Scott

Enclosures

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF DELAWARE

IN THE MATTER OF THE APPLICATION OF DELMARVA POWER & LIGHT COMPANY FOR AN INCREASE IN ELECTRIC BASE RATES AND MISCELLANEOUS TARIFF CHANGES (FILED March 22, 2013)	))))))	PSC DOCKET NO. 13-115

POST-HEARING REPLY BRIEF OF DELMARVA POWER & LIGHT COMPANY

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February 5, 2014

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POST-HEARING REPLY BRIEF OF DELMARVA POWER & LIGHT COMPANY

Delmarva Power and Light Company (Delmarva or the Company) submits this Post-Hearing Reply Brief in response to the briefs submitted by the Staff of the Public Service Commission ("Staff") and the Delaware Division of the Public Advocate ("DPA").[1]

SUMMARY OF ARGUMENT

In this Reply Brief, Delmarva responds to the extensive briefs submitted by Staff and DPA. Delmarva will not belabor the Hearing Examiner and the Commission with another tome in reply, nor will Delmarva respond in kind to the commentary and rhetoric prevalent throughout

[1] Staff's Post-Hearing Brief will be cited as "Staff AB at _" and DPA's Post-Hearing Brief will be cited as "DPA AB at _"

the briefs of Staff and DPA disparaging the Company and its witnesses.[2] Instead, the Company will address what it views as the incorrect application of several themes by Staff and DPA, as well as some of the more significant assertions made in their briefs.[3]

ARGUMENT

I. DELMARVA'S PROPOSED RATES REFLECT THE COST OF PROVIDING SERVICE DURING THE RATE EFFECTIVE PERIOD AND THE PROPOSED POST-TEST PERIOD ADJUSTMENTS ARE PROPER UNDER THE COMMISSION'S RULES AND PRECEDENT.

A. The Fact That Delmarva May Need To File Rate Cases As Often As Annually, Depending On The Outcome Of Multiple Issues, Does Not Mean That Delmarva Should Be Denied Recovery Of Post-Test Year Adjustments That Are Provided For By Both Established Commission Precedent And The Minimum Filing Requirements

Staff and DPA both assert that the potential for more frequent rates cases by the Company negates the need for post-test period adjustments or inclusion of certain deferred costs

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[2] Staff's brief contains acrimony, sarcasm and derisive language. By way of limited example:

> "Apparently $65 million dollars in additional rates approved by this Commission over the last two and a half years is not enough for this utility – it seeks more revenue from its weary ratepayers." (Staff Brief at page 1)
>
> "Delmarva makes a mockery of the test year" (Staff Brief at Page 1)
>
> "This rate case is not prompted by the company's actual needs as much by its greed." (Staff Brief at Page 2)
>
> "the Company's avarice needs to be curbed." (Staff Brief at Page 4)
>
> "Mr. Maxwell is [not] the oracle of what is the appropriate . . . ('SAIDI')." (Staff Brief at Page 12)

The Delaware Courts have held that this type of acrimonious language is inappropriate in written advocacy. *395 Assocs., LLC v. New Castle Cnty.*, 2005 WL 3194566 , at * 4 (Del. Super., Nov. 28, 2005) (attached as Att. 1) ("this Court will not '[condone] ... accept or permit the use of profanity, derisive gibes, or sarcasm with respect to any communication related to any matter, proceeding, writing, meeting, etc.' involved in pending cases.") (*citing Crowhorn v. Nationwide Mut. Ins. Co.*, 2002 WL 1274052, at *5 (Del. Super. May 6, 2002)). *See, In re Abbott*, 925 A.2d 482, 485 (Del. 2007) ("Use of such language does nothing to assist the Court in deciding the merits of a motion, wastes judicial resources by requiring the Court to wade through the superfluous verbiage to decipher the substance of the [written submission], does not serve the client's interests well, and generally debases the judicial system and the profession."). Delmarva is confident that the Hearing Examiner will not allow this unnecessary style of written advocacy to color his perception of the important facts and legal issues in this case.

[3] The fact that, in order to avoid burdening the Hearing Examiner with another extensive document, Delmarva has chosen not to reply to each and every argument raised in the extensive briefs of Staff and DPA does not constitute agreement with such arguments.

in rates. Such arguments are incorrect and will lead to rates that do not reflect the cost of providing service during the rate effective period.

First, this argument is advocating strict test period construction based upon an event (i.e., a potential rate filing in 2014) that may, or may not, happen. By expressly rejecting strict test period construction in PSC Docket No. 09-414, the Commission recognized that the inclusion of known and measurable post-test period costs in rate base may make "the test period more reflective of the period during which the rates approved in this case will be in effect."[4] The Commission recognized that "[o]ur MFRs[5] expressly authorize utilities to propose, and our practice for many years has been to consider, post-test period adjustments to recognize known and measureable changes in rate base, expenses and revenues."[6] That is, "the utility can *also* suggest that its test period rate base, expense or revenue level be adjusted based on an event that is reasonably likely to occur, although outside the selected test period."[7] This is so that the test period levels will be "representative of what can be expected in the rate effective period."[8]

In this proceeding, particular focus is made on the Company's inclusion of a post-test period adjustment for one-year of reliability plant closings ("Adjustment Nos. 26 (a) and (b)"). The Company agrees that the combined period for both Adjustment Nos. 26 (a) and (b) is longer than previous post-test period adjustments for reliability plant closings approved by the Commission in PSC Docket Nos. 05-304 and 09-414 by several months. Yet, the adjustment is no less valid due to the time period. The Adjustment No. 26 (a) costs are expressly "known and measurable" because those costs have been incurred for reliability infrastructure investments that

[4] PSC Order No. 8011 ¶ 60. This Commission is not alone in allowing post-test period adjustments. As described by Staff Witness Peterson at the evidentiary hearing: "Based on the research that I've done on Commission practices with regard to test years, about half of them rely on forecast test years and half of them rely on historic test years with adjustments for known changes." Tr. at 499:9-13 (Peterson Cross).

[5] "MFR" stands for "Minimum Filing Requirements."

[6] *Id.* ¶ 48.

[7] *Id.* ¶ 49.

[8] *Id.*

are completed, are in service and are used and useful. The costs in Adjustment 26 (a) are for capital investments that are completed and are providing actual service to customers as of the filing of Delmarva's rebuttal testimony in this case. Pursuant to Commission precedent from Docket Nos. 05-304 and 09-414, Delmarva is permitted to recovery of and on the investments contained in Adjustment No. 26(a).[9]

Adjustment No. 26 (b) represents post test period adjustments for reliability capital investments that, as of the filing of Delmarva's rebuttal testimony, were not yet completed, but were forecasted to be used and useful by December 2013 – well within the rate effective period.[10] For the reasons detailed in Delmarva's Opening Brief, Delmarva asks the Commission to allow recovery of the Adjustment 26 (b) investments because they are reasonably "known and measurable." Adjustment No, 26 (b) is for reliability closings during the rate effective period. Thus, this adjustment and its time period is highly representative of the rate base for the rate effective period.

Staff and DPA also opposed the Company's recovery of certain deferred costs in this proceeding relating to the Dynamic Pricing and Direct Load Control programs, notwithstanding that a portion of the costs for these programs are known and measurable. In fact, these are not even all of the post-test period costs related to these programs and Delmarva's customers have received benefits from the programs. Continuing to defer the recovery of such costs, which will only result in a larger accrual of return, is not beneficial to customers, and the proposed adjustments will make the rates from this proceeding reflective of the rate effective period.

The Company established through the evidence in this case that it has made investments in its system, and those investments have improved the reliability that customers experience.

[9] *See* PSC Order No. 6390 ¶ 39; PSC Order No. 8011 ¶ 60.

[10] The rate effective period in this case began on October 22, 2013 (when the Commission permitted Delmarva to put rates into effect subject to refund) and will end on October 21, 2014.

Based on the evidence and the applicable precedent, as well as the limited extensions to prior precedent, the Company's request should be granted.

B. Staff's Assertion That Delmarva Should Be Denied Any Post-Test Year Reliability Capital Adjustments Because The Adjustment 26 (a) and (b) Reliability Investments Are Allegedly Being Reviewed As Part Of An Ongoing Investigation Is Erroneous

Throughout its Brief, Staff asserts that Delmarva may not be awarded any post-test year adjustments (Adjustments 26 a and 26 b) because the Commission has opened Docket 13-152, known as the "Investigation into [Delmarva's] Planned Distribution Infrastructure Investment for the Next Five Years" ("Docket 13-152" or the "Reliability Investigation").[11] In support of that argument, Staff claims that Delmarva's request to recover for post-test year reliability adjustments "is the very subject that Docket 13-152 was opened to review."[12] Staff's argument is factually incorrect and seeks to violate Delmarva's specifically enumerated right to due process under Delaware's Administrative Procedures Act.[13]

As described above, Commission precedent firmly establishes a utility's ability to recover for post-test year adjustments in rate cases.[14] The Commission has also made it clear that "the MFRs[15] expressly authorize utilities to propose, and our practice for many years has been to consider, post-test period adjustments to recognize known and measureable changes in rate base, expenses and revenues."[16] Accordingly, it is settled that a request for post-test period adjustments is a proper subject of a base rate proceeding. It was, therefore, entirely appropriate for Delmarva to seek post-test period reliability capital adjustments in this docket when it filed

[11] Staff Brief at pages 20-21. *See id.* at 9, 19, 52.
[12] Staff Brief at page 20.
[13] 29 *Del.C.* § 10124.
[14] PSC Order No. 8011 ¶ 60. *See also, In re Delmarva Power & Light Co.*, 1992 WL 465021, Docket No. 91-20, Order No. 3389 ¶ 50 (P.S.C., March 31, 1992) and *Application of Delmarva Power & Light Co.*, 337 A.2d 517, 518. (Del. Super 1975).
[15] "MFR" is an acronym for "Minimum Filing Requirements."
[16] PSC Order No. 8011 ¶ 48.

this base rate case in March 2013.

Staff filed its petition to open Docket 13-152 on April 16, 2013, nearly a month after Delmarva filed this base rate proceeding, and the Commission opened the docket on May 7, 2013.[17] Staff retained a consultant to investigate Delmarva's future reliability capital investment plans. No schedule exists for the Docket 13-152 investigation and Delmarva has been provided with no indication as to when it can expect a report from Staff's consultant in the matter. Because it is an "investigation," Docket 13-152 provides no opportunity for Delmarva to conduct discovery and provides no opportunity for Delmarva to put on evidence in a hearing or cross examine witnesses against it.

The clear language of the Delaware Administrative Procedures Act (the "APA") prohibits Staff from seeking to use a Commission investigation to prevent Delmarva from recovering post–test year adjustments in this rate making proceeding. The APA specifically provides that "when the matters at issue involve price fixing, rate making or similar matters of general public interest . . . the agency *shall* conduct a formal, public evidentiary hearing . . . ."[18] By arguing that Delmarva's post-test period reliability capital adjustments (Adjustments 26 a and 26 b) cannot be recovered in this rate case because Delmarva's right to recover for those investments "is the very subject that Docket 13-152 was opened to review,"[19] Staff seeks to violate Delmarva's rights under the APA.[20] Investigations do not entail the same procedures required under the Delaware APA, and accordingly, the post-test year reliability adjustments must be

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[17] Commission Order No. 8363 opening Docket No. 13-152.S.

[18] 29 *Del. C.* § 10124 (*emphasis added*). *See Carousel Studio v. Unemployment Ins. Appeal Bd.,* 1990 WL 91108, at *1 (Del. Super. June 26, 1990) ("Due process as it relates to the requisite characteristics of the proceedings entails providing the parties to the proceeding with the opportunity to be heard, by presenting testimony or otherwise, and the right of controverting, by proof, every material fact which bears on the question of right in the matter involved in an orderly proceeding appropriate to the nature of the hearing and adapted to meet its ends.") (attached to this Brief as "Att. 2").

[19] Staff Brief at page 20.

[20] 29 *Del. C.* § 10124. *Carousel Studio,* 1990 WL 91108, at *1.

considered as part of this rate proceeding. To do otherwise would be to reassign a matter that involves rate making out of a "formal, public evidentiary hearing," an action plainly untenable under the APA.[21]

Moreover, Staff's erroneous assertion that Delmarva's post-test period reliability capital adjustments (Adjustments 26 a and 26 b) cannot be recovered in this rate case because Delmarva's right to recover for those investments "is the very subject that Docket 13-152 was opened to review,"[22] is both factually incorrect and contradictory to the reasons Staff provided to the Commission as to why it was necessary to open the Reliability Investigation docket. During argument on Staff's Petition to open Docket 13-152, counsel for Staff told the Commission that the Reliability Investigation is needed to review future investments, through 2017, that cannot be reviewed in the current base rate case.[23] Moreover, the Commission made clear that it relied on the representation from Staff's counsel that the purpose of the 13-152 Reliability Investigation is to investigate future reliability capital spending that cannot be reviewed in this base rate case.[24]

[21] 29 *Del. C.* § 10124.

[22] Staff Brief at page 20.

[23] Staff's counsel told the Commission:

> "the reason why this *will not work in this rate case* is because first, as you know, . . . rate cases are pretty much accounting cases, green eye shape, how much investment, what's the return, what kind of revenues do we have and what's the deficiencies that the company should be entitled to collect…." (excerpts from transcript from April 23, 2013 oral argument in 13-152, Page 7, ln 11-17, attached hereto as Att. 3)(*emphasis added*))
>
> ***
>
> "This [Reliability Investigation] is not accounting. This is something that's a lot bigger, and it's going to require a lot of effort. *It cannot be done in a single [rate] case.* And it clearly stretches out until 2017." (*Id.* at page 13, ln 14-17) (*emphasis added*).

[24] Chair Winslow stated as follows:

> "the argument made by Mr. Geddes [is] that there are issues in this particular request by Staff that are beyond the scope of the rate base case…." (*Id.* at page 37, ln 5-10). "[T]he Staff wants to know about the future. There are a lot of the discussions, obviously, some of the discussions are about the future. But that is what they are really looking at." (*Id.* at page 38, ln 10-13). [I]t appears to me from my hearing of the discussion that Ms. Iorii agrees with Mr. Geddes that there will be items outside of the relevant inquiry at the rate base case that they would, or that you could successfully object to if it were in the rate base case….. There seems to be a different element here." (*Id.* at page 38, ln 15-22).

Accordingly, Staff's argument not only seeks to violate Delaware's APA, but in addition, it is inconsistent with both Staff's prior representations as to the purpose of the Reliability Investigation and the Commission's acceptance of those reasons as argued by Staff.

II. RELIABILITY

A. Staff Argues For Various Incorrect Burdens Of Proof And Mischaracterizes Delmarva's Position Regarding The Correct Burden Of Proof

At pages 11-12 of its brief, Staff argues that the standard for recovery of and on investments by a utility in Delaware is not governed by the Delaware Supreme Court's opinion in *Delmarva Power & Light Company v. Pub. Serv. Comm'n.*[25] Staff's argument is incorrect. The Delaware Supreme Court has clearly established that a utility is entitled to recovery of and on its investments "in the absence of a finding of waste, inefficiency or bad faith."[26] However, citing *Chesapeake Utilities v. Pub. Serv. Comm'n*, Staff asserts that the standard is "used and useful."[27] Staff is, again, incorrect. The *Chesapeake* decision upon which Staff relies does not address whether an investment is recoverable or what the standard of proof for recovery by a utility is. Rather, that case specifically addresses the narrow issue of whether the utility is entitled to carrying costs on an otherwise recoverable cost. Specifically, the *Chesapeake Utilities* Court considered whether an unamortized balance of environmental remediation costs (*that the Commission had already determined was recoverable by the utility*) should be recovered in rate base as "utility plant," (subject to recovery of carrying costs) or whether it should be recovered through a rider (without carrying costs).[28]

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[25] *Delmarva Power & Light Co. v. Pub. Serv. Comm'n.*, 508 A.2d 849, 859 (Del. 1986).
[26] *Id.* at 859.
[27] See Staff brief at page 12 (citing *Chesapeake Utilities Corp. v. Del. Pub. Serv. Comm'n*, 705 A.2d 1059, 1071 (Del. Super., 1977)).
[28] The *Chesapeake* Court described the issue as follows:

> "Must the Delaware Public Service Commission allow a public natural gas utility

In the *Chesapeake* case, a natural gas utility appealed the Commission's determination that, although the unamortized balance of an environmental remediation cost *is* recoverable, that balance was not "used and useful" utility plant and, therefore, the utility was not entitled to carrying costs. The Commission had ruled that under 26 *Del. C.* §102 (3), remediation costs were not utility plant "because the land to which the remediation costs related was no longer 'used and useful' in the provision of utility services to Chesapeake's customers."[29] On appeal, the Superior Court affirmed the Commission's determination that the unamortized balance of environmental remediation costs was not used and useful and therefore, did not constitute utility plant.[30] As such, the Court upheld the Commission's determination that the non "used and useful" investment was *recoverable,* but that the utility was not entitled to carrying costs on the balance.[31] The *Chesapeake* decision does not alter the well-established standard that a "finding of waste, inefficiency or bad faith" by the Commission is required to deny a utility recovery.[32] The *Chesapeake* decision held only that the unamortized balance of remediation costs is not "utility plant" because it does not constitute used and useful property and, therefore, although the utility *is entitled to recovery,* it is not entitled to carrying costs.[33]

What the *Chesapeake* case does clearly establish, however, is that Delmarva's reliability plant investments are "used and useful" utility plant. As the *Chesapeake* Court stated:

> [A] review of the Public Utilities Act and general authorities indicates that "utility plant" is the physical objects and structures comprising a utility's operations and which it uses to provide service to its customers. A utility's "plant" is, essentially, the

company to recover, as a consequence of complying with federally-mandated environmental remediation, the entire cost of compliance, specifically including the carrying costs on the unamortized balance of the remediation expenditure recovery? This is the underlying question in issue on this appeal..." *Chesapeake*, 705 A.2d at 1061.

29 *Id.* at 1070.

30 *Id.*

31 *Id.*

32 *Delmarva Power*, 508 A.2d at 859.

33 *Chesapeake*, 705 A.2d at 1070.

tangible property it devotes to the public service.[34]

The evidence of record in this docket firmly establishes that Delmarva's reliability infrastructure investments are used and useful. In fact, Staff Witness Vavro specifically acknowledges that Delmarva's reliability plant investments have resulted in noticeably improved reliability for its customers:

> "there has been a noticeable improvement in SAIDI performance since the REP reliability-related initiatives began. To be clear, we are not challenging the Company's selection of projects in its REP, or questioning whether those projects might have a positive effect."[35]

Accordingly, pursuant to Staff's own testimony, established Delaware law and the clear facts of record in this case, Delmarva's reliability investments are "used and useful" utility plant. Delmarva is entitled to recovery of and on its reliability plant investments "in the absence of a finding of waste, inefficiency or bad faith."[36]

At page 15 of its brief, Staff argues for yet another incorrect standard of proof. Staff asserts that to meet its burden of proof, Delmarva must establish "that it could not provide safe, adequate and proper service to its customers without these dramatically escalating capital expenditures."[37] Staff offers no citation to authority for this proposed standard. Again, the law is well–established: Delmarva must bear its burden of proving that its decisions regarding its reliability investments were the result of the exercise of "professional judgment."[38] As addressed above, Delmarva must also establish that the reliability infrastructure investments constitute used

[34] *Id.*
[35] Delmarva's Opening Brief Ex 12, Vavro Direct at p 13, ln 4 – 7.
[36] *Delmarva Power*, 508 A.2d at 859.
[37] Staff argues as follows: "the Company has failed to meet its burden of proof that it could not provide safe, adequate and proper service to its customers without these dramatically escalating capital expenditures." Staff's Brief at page 15
[38] Docket 50 - 26 *Del. Admin. C.* § 3007 § 1.3

and useful utility plant.[39] Once Delmarva meets its burden, it is entitled to recovery "in the absence of a finding of waste, inefficiency or bad faith."[40]

B. Delmarva Has Not Misconstrued The Docket 50 Standards And Does Not Seek To Avoid The Commission's Regulatory Authority

Contrary to the assertions of Staff, Delmarva does not offer a "confusing" and "misleading" analysis of Regulation Docket 50 ("Docket 50"),[41] nor does Delmarva seek to "unilaterally decide,"[42] to "self regulate itself [*sic*]" and "spend whatever it wants...."[43] Staff's characterizations are not supported by either the record or Delmarva's position set forth in its Opening Brief.

Despite the efforts of both Staff and DPA to confuse the issues, the standard that Delmarva must follow in planning, investing in, and maintaining the reliability of its system are clear. As Delmarva described in detail in its opening brief, the Commission adopted the Docket 50 reliability standards in 2006.[44] Docket 50 contains broad provisions concerning achieving, maintaining, measuring and reporting on reliability and service quality issues. Docket 50 requires Delmarva to maintain, at a minimum, a SAIDI that does not exceed 295 minutes.[45] Docket 50 further provides:

1. "Compliance with this regulation is a minimum standard,"[46]

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[39] *See Chesapeake*, 705 A.2d at 1070. As this Commission and the Delaware Courts have also held, consideration of post-test period information is appropriate for prospective ratemaking and post-test year adjustments are permitted where the plant will be placed into service during the rate effective period and the costs are sufficiently ascertainable. *See Application of Delmarva Power & Light Co.*, 337 A.2d 517, 518 (Del. Super. 1975)(internal citations excluded); *IMO the Application of the Delaware Division of Chesapeake Utilities Corporation for a General Increase in Natural Gas Rates and Charges Throughout Delaware and for Approval of Other Tariff Changes* (Filed April 4, 1995) Docket No. 95-73, Order No. 4104 at VII(B)(2) (December 19, 1995); and PSC Order No. 8011 ¶ 48. The appropriate standards with respect to post-test year adjustments (Adjustment 26 a and 26 b) are addressed in Delmarva's Opening Brief.

[40] *Delmarva Power*, 508 A.2d at 859.

[41] Staff Brief at page 13

[42] *Id.* at page 14.

[43] *Id.* at page 15.

[44] *See*, *26 Del. Admin. C.* § 3007 *et. seq.*

[45] *Id.* § 4.3.1.2.

[46] *Id.* §1.3.

2. "Compliance [with SAIDI 295] does not create a presumption of safe, adequate and proper service,"[47]

3. "Each EDC[48] needs to exercise their professional judgment based on their systems and service territories"[49] and

4. "EDCs are required to explore the use of proven state of the art technology, to provide cost effective electric service reliability improvements."[50]

Docket 50 makes it clear that achieving the "minimum standard" SAIDI of 295 minutes "does not create a presumption" that Delmarva has met the requirement of providing "safe, adequate and proper service."[51] Docket 50 specifically requires that Delmarva's engineers and managers must exercise their "professional judgment based on their systems and service territories" to determine what level of reliability the Company should seek to provide to its customers.[52] Finally, Docket 50 specifically provides that Delmarva must remain vigilant in its efforts to use "state of the art technology" to provide actual "cost effective electric service reliability improvements" to its Delaware customers.[53]

Despite Staff's argument that Docket 50's specific requirement that Delmarva must exercise its "professional judgment based on [its] systems and service territories" is not to be followed, the language of Docket 50 could not be clearer. That "professional judgment" requirement was adopted by the Commission in 2006 and it is consistent with established Delaware law and Commission precedent holding that the Commission's duty to regulate utilities does not entail dictating the day to day operations and decisions made by utility company

[47] *Id.*
[48] "EDC" stands for "Electric Distribution Company." *Id.* at § 1.1.
[49] *Id.* § 1.3.
[50] *Id.* § 1.8.
[51] 26 *Del. Admin. Code.* § 3007 at §1.3 (*citing* 26 *Del.C.* § 209 (a) (2).
[52] *Id.*
[53] 26 *Del. Admin. Code. C.* § 3007 at § 1.8.

management.[54] It is Delmarva who has a staff of specialized utility distribution engineers who, on a day-to-day basis, are responsible for designing and maintaining a reliable and safe distribution system. It is Delmarva who must, on a day-to-day basis, plan, construct and maintain a system that can meet the evolving reliability expectations of its customers. And it is Delmarva who carries the burden of exercising its professional judgment, discretion and good faith in carrying out those obligations.

Contrary to the flawed rhetoric of Staff and DPA, Delmarva has never "divine[d] that it can regulate itself and infer[ed] that it can set its own standards unilaterally."[55] The Docket 50 regulations and established Delaware law require Delmarva to exercise "professional judgment," based upon Delmarva's unique experience and expertise with its customers, its system and service territories, to determine how its system must be planned, constructed and maintained.[56] If Delmarva does not exercise its "professional judgment" in determining how to invest in its distribution system, then it will have violated the established Delaware requirement that it not engage in "waste, inefficiency or bad faith" or an "abuse of discretion."[57] If Delmarva violates that well-established standard, the Commission will deny recovery. The facts of record in this case are clear that Delmarva has satisfied that standard.

Delmarva's Opening Brief accurately reviewed the uncontroverted evidence in the record establishing that Delmarva exercised professional judgment in making the two key determinations related to reliability investments: (1) Delmarva exercised professional judgment in determining that reliability investments needed to be increased both to prevent a degradation of reliability and to provide an appropriate level of enhanced reliability for its customers, and (2)

[54] *See*, *Delmarva Power*, 508 A.2d at 859 ("[A]public utility commission shall not dictate business practices to be followed by a utility."), *citing Application of Wilmington Suburban Water Corp.*, 203 A.2d 817, 829 (Del. Super. 1964).
[55] Staff Brief at page 13.
[56] 26 *Del. Admin. C.* § 3007, § 1.3
[57] *Delmarva Power*, 508 A.2d at 859 and 829.

Delmarva exercised professional judgment in the reliability project initiatives it chose in order to maintain and enhance reliability for its customers.[58] The evidence of record in this docket establishes that Delmarva's reliability investments are appropriate and in full compliance with Delaware law, Delaware regulations and Commission precedent.

As set forth in detail in Delmarva's Opening Brief, Delmarva's decision that its reliability investments needed to be increased for the purpose of enhancing and maintaining reliability was based upon five principal factors:

(1) The increasing need for reliable service to meet the needs of an increasingly digital society and economy;

(2) The increase in the frequency and severity of storms;

(3) The need to replace aging and degrading infrastructure, including URD cables, substation transformers and switchgear;

(4) The quarterly surveys from MSI and JD Power & Associates that have consistently found that the most important driver of satisfaction to Delmarva Power's customers is "providing reliable electric service" and "restoring outages when they occur."

(5) How Delmarva's reliability performance compares with respect to other electric delivery utilities in the United States – namely, the annual IEEE national survey revealing that had Delmarva not increased its reliability investments to improve its SAIDI performance from the 192-199 minute range, where it was from 1998 – 2011, Delmarva's current reliability performance would be among the worst performing utilities in the IEEE national survey.[59]

Based upon an analysis of these factors, Delmarva's reliability engineers exercised their professional judgment to conclude that an increase in reliability infrastructure investment was necessary both: (1) to "furnish safe[,] adequate and proper service and keep and maintain its property and equipment in such condition as to enable it to do so," as required by Delaware

[58] *See* Delmarva Opening Brief at pages 11-19.
[59] Delmarva Opening Brief at pages 11-19.

statute[60] and (2) to comply with Docket 50's clear mandate requiring Delmarva to "exercise their professional judgment based on [Delmarva's] system[] and service territor[y]" to determine the level of reliability necessary to meet the reasonable expectations of its customers.[61]

Once Delmarva determined that it was necessary to increase its investments in reliability infrastructure, Delmarva relied upon sound engineering principles, long-standing utility practices and proven state of the art technology in selecting specific infrastructure investments necessary to meet its reliability obligation objectives.[62] Delmarva adopted four primary reliability infrastructure investment initiatives designed to maintain and enhance reliability of the electric system.[63] Those four primary initiatives, which are addressed in detail in Delmarva's Opening Brief at pages 19-25, consisted of the following:

a. Load Growth and Load Maintenance Projects, including, New Load Growth Projects, and

b. Replacing Deteriorated Aging Infrastructure to Prevent Load Related Outages.

2. Priority Feeders,

3. URD Cable Replacement (And Other Aging Infrastructure, including Substation Transformers and Switchgear), and

4. Distribution Automation ("DA").

As Staff's own reliability witness testified, those increased investments have been effective in improving reliability for customers from the SAIDI 192 – 199 minutes range (in 2010 and 2011) to a SAIDI of 146 minutes in 2012.[64] Staff's reliability witness further testified that she does not challenge the reliability infrastructure projects selected by Delmarva.[65]

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[60] 26 *Del. C.* § 209 (a) (2).
[61] 26 *Del. Admin. C.* § 3007, § 1.3; Delmarva Opening Brief at pages 11-19.
[62] These investments are discussed in detail in Delmarva's Opening Brief at pages 19-25.
[63] *Id.*
[64] "[T]here has been a noticeable improvement in SAIDI performance since the REP reliability-related initiatives began." Vavro Direct at p 13, ln 4 – 7.
[65] "To be clear, we are not challenging the Company's selection of projects in its REP, or questioning whether those

In their brief, both Staff and DPA take issue with some of the five principal factors upon which Delmarva relied in making its determination that reliability investments needed to be increased. For example, Staff argues that it was somehow inappropriate for Witness Maxwell to place reliance upon customer surveys as one of the five primary factors that guided Delmarva's reliability decisions.[66] Staff argues that "Exhibit 83 shows a lower customer satisfaction for reliability – now – than before the Commission had reliability standards, and before the Company spent millions of dollars on reliability improvements."[67] In support of that argument, Staff asks the Hearing Examiner to "[c]ompare the average of 2001-2004 (87%)" customer satisfaction with reliability to the "average for 2010-12 (85%)."[68]

Staff's argument that a 2% change in customer satisfaction over an 11 year period means that Customer satisfaction with reliability "cannot be as important a driver as the Company suggests" is both erroneous and trivial. The uncontroverted fact remains that quarterly surveys of Delmarva's customers have consistently found that the most important driver of satisfaction to Delmarva Power's customers is reliability: "providing reliable electric service" and "restoring outages when they occur."[69] To Delmarva, addressing the number one concern of customers – reliability - is an important factor. Clearly, reliability is important to Delmarva's customers as well.

The Public Advocate and Staff argue that Delmarva is only investing in reliability in Delaware because of the experience of its affiliate, Pepco, in Maryland.[70] In fact, DPA dedicates nearly four pages of its Answering Brief to single-spaced block quotations from the Maryland

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projects might have a positive effect." Vavro Direct at p 13, ln 4 – 7.

66 Staff Brief at page 16.

67 *Id.*

68 *Id.* at page 16, footnote 32.

69 Maxwell Rebuttal at p 6, ln 9-14; Schedule (MWM-R)-1 to Maxwell Rebuttal; Hearing Trans at p 750, ln 6 – p 751, ln 14; p 753, ln 11 – p 756, ln 15; and Hearing Exhibit 83.

70 DPA AB at pp. 21-26.

Commission's order finding that Pepco, MD did not meet its reliability obligations to Pepco customers in 2010.[71]

The reliance by DPA and Staff on that argument is misplaced. In the Pepco, Maryland reliability case (MD Docket No. 9240), Pepco was *not* found to have violated any Maryland SAIFI or SAIDI performance standard. In fact, the performance of Pepco Maryland would have complied with Delaware's minimum 295 minute SAIDI standard. Nevertheless, Pepco was penalized for inadequate reliability performance in Maryland.[72] Notwithstanding those facts, DPA argues that "in Delaware, however, Delmarva had no such reliability problems. It was meeting its Docket 50 reliability standards with relative ease."[73]

Both DPA and Staff fail to recognize a seemingly obvious point. Delmarva did learn from Pepco's experience in Maryland.[74] Delmarva learned that providing reliability performance that merely complied with the Delaware Docket 50 minimum of 295 SAIDI minutes was considered entirely unsatisfactory to Pepco's Maryland customers. Delmarva learned from the Pepco Maryland experience that customers require more than the Docket 50 bare minimum level of reliability.[75] Along with the five primary factors addressed above and in Delmarva's Opening Brief, Pepco's Maryland reliability experience did help guide Delmarva's decision that reliability investments in Delaware needed to be increased. What would have been improper would have been for Delmarva to not have learned from the experience of its Pepco affiliate.

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[71] *Id.* at pp. 21-24. (*quoting* Maryland Commission Order No. 84564 in Docket No. 9240).
[72] *See*, Maryland Commission Order No. 84564 in Docket No. 9240.
[73] DPA AB at pg 26.
[74] As Delmarva Witness Maxwell testified in his Rebuttal Testimony:

> "It is true that Delmarva learned from Pepco's Maryland experience and is applying that knowledge across its sister companies. The fact that Delmarva is applying lessons learned from other jurisdictions should not be seen as a negative, but rather as one of the benefits of having the experience of a larger corporate group on which to draw." (Maxwell Rebuttal at pg 13, ln 3-6.)

[75] *Id.*

Staff also takes issue with the fact that Delmarva considers its reliability performance compared to its peers as another of the five principal factors upon which Delmarva relied in making its determination that reliability investments needed to be increased. The following facts are uncontroverted:

(a) in 2010 and 2011, before Delmarva's increased investments in reliability began, Delmarva's SAIDI performance was 199 and 192 minutes, respectively,[76]

(b) in 2012, after Delmarva began to increase investments in reliability infrastructure, Delmarva's SAIDI performance improved to 146 minutes,[77] and

(c) as the IEEE survey chart on page 18 of Delmarva's Opening Brief and Mr. Maxwell's testimony clearly reveals, had Delmarva not increased its reliability investments and, therefore, its SAIDI remained in the 192-199 minute range in 2012, Delmarva's current reliability performance would be among the worst performing utilities in the IEEE national survey - in the middle of the worst (4th Quartile) performers.[78]

In response to those uncontroverted facts, Staff offers two arguments. First, Staff states as follows:

> [N]o party to this proceeding is recommending that the Company stay in the fourth quartile, and Staff recognizes that Delmarva's SAIDI has come down after spending millions of dollars on reliability improvements. That is not the point. The issue is the amount being spent and the timing of those expenditures. Is it all needed now? There is no evidence of record that it is.[79]

Staff's argument is meritless. On one hand, Staff asserts that Delmarva acted appropriately in making investments that brought its SAIDI performance out of the lowest performing fourth quartile of utilities. In the next sentence, however, Staff argues that Delmarva spent too much and that its timing in making the reliability investments was wrong. Nevertheless, despite retaining a reliability consultant (Ms. Vavro of Silverpoint), who submitted

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[76] Maxwell Direct at p 5, ln 16 – p 6, ln 12.
[77] *Id.*
[78] *See*, chart at page 18 of Delmarva's Opening Brief, which also appears in the Maxwell Rebuttal at p 8, ln 1 – 2.
[79] Staff Brief at page 17.

testimony in this docket, Staff failed to offer any evidence that Delmarva's decisions on reliability infrastructure were the result of a failure to exercise "professional judgment" required by Docket 50[80] or that Delmarva engaged in "waste, inefficiency or bad faith."[81] In fact, Ms. Vavro made it very "clear" that she was not challenging the reliability infrastructure projects selected by Delmarva. [82]

Despite Staff's admission that it was appropriate for Delmarva to improve its 2011 4th quartile SAIDI 295 minute performance and that Docket 50 requires Delmarva to "exercise their professional judgment based on their systems and service territory[y]," Staff argues that Delmarva invested too much and seeks a SAIDI performance that is too reliable. Staff provides no evidence of what was too much; no evidence of what projects should not have been pursued; no evidence concerning what level of reliability investment would have been appropriate; and no testimony concerning what conduct allegedly constituted a failure to exercise "professional judgment"[83] or "waste, inefficiency or bad faith."[84] Simply stated, there was no evidence offered in this docket challenging the overwhelming evidence that Delmarva exercised "professional judgment" in making its reliability infrastructure investments and there was no evidence offered by any witness that Delmarva engaged in "waste, inefficiency or bad faith."[85]

Next, using a chart prepared by Ms. Vavro for the purpose of comparing Delmarva's SAIDI performance to other Mid-Atlantic utilities, Staff argues that "a more relevant comparison of where Delmarva's system performance ranks is to compare it to other electric utilities

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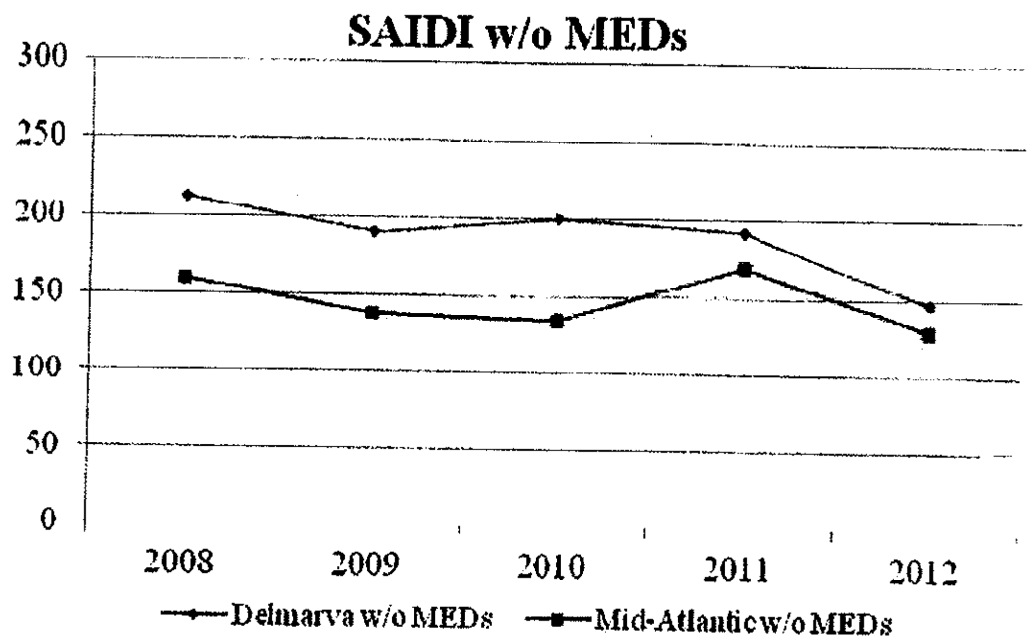
[80] 26 *Del. Admin. C.* § 3007, § 1.3.
[81] *Delmarva Power*, 508 A.2d at 859.
[82] "To be clear, we are not challenging the Company's selection of projects in its REP, or questioning whether those projects might have a positive effect." Vavro Direct at p 13, ln 4 – 7.
[83] *See*, 26 *Del. Admin. C.* § 3007, § 1.3.
[84] *See*, *Delmarva Power*, 508 A.2d at 859.
[85] *Id.*

operating in the Mid-Atlantic region."[86] Staff then asserts that "Delmarva's performance on a system basis is comparable with other utilities in the region."[87] Assuming that Ms. Vavro's Mid-Atlantic SAIDI performance chart is correct, it serves to further support the overwhelming evidence that Delmarva's decision to invest in reliability to maintain and improve its reliability performance was an appropriate decision (made in the exercise of "professional judgment" and without "waste, inefficiency or bad faith").



Staff's Mid-Atlantic SAIDI Chart[88]

Staff's Mid-Atlantic SAIDI chart (reproduced above) clearly reveals that from 2011-2012, the Mid-Atlantic SAIDI average improved from approximately 170 minutes to

86 Staff Brief at 17.
87 *Id.* at 18.
88 Staff's Mid-Atlantic SAIDI Chart Appears in Staff's Answering Brief at page 17 and is Hearing Exhibit 83. It has been reproduced and incorporated into Delmarva's Answering Brief for the convenience of the Hearing Examiner.

approximately 130 minutes.[89] During the same period, as a result of Delmarva's increased reliability infrastructure investments, Delmarva's SAIDI also improved from 192 minutes in 2011 to 146 minutes in 2012.[90] The Mid-Atlantic SAIDI chart proves that Mid-Atlantic utilities, like Delmarva, have recognized the need to improve reliability - and like Delmarva, have taken action to do so.[91] Staff's Mid-Atlantic SAIDI chart shows that Delmarva's decision to increase its reliability performance is consistent with the realization of the industry (both nationwide and in the Mid-Atlantic Region) that reliability needs to be improved, therefore, offering further support that Delmarva's reliability investment decisions were the result of "professional judgment" and are, therefore, fully recoverable under established Delaware law and Commission precedent.[92]

Moreover, as set forth in Delmarva's Opening Brief, the uncontroverted evidence of record also shows that Delmarva's decision that increased reliability investments are necessary is consistent with the opinions and calls to take action by the American Society of Civil Engineers, [93] the President's Council of Economic Advisors and the U.S. Department of Energy.[94] These

89 Ms. Vavro's Mid-Atlantic SAIDI chart does not reveal what the specific Mid-Atlantic SAIDI number is and no number was provided in the record. Nevertheless, Delmarva is willing to accept that the 2012 Mid-Atlantic SAIDI average, according to Ms. Vavro's chart, appears to be approximately 130 minutes and that the average in 2011 was approximately 170 minutes.

90 *Id.*

91 The Mid-Atlantic SAIDI chart also establishes that had Delmarva not increased its reliability investments from 2011-2012 and, therefore, its SAIDI remained in the 192-199 minute range in 2012, Delmarva's reliability performance would have lagged significantly behind the Mid-Atlantic SAIDI average by approximately 70 minutes.

92 The Public Advocate actually goes so far as to assert that Delmarva is "Gold plating a distribution system" (DPA Brief at 4). Delmarva's current improved SAIDI performance, compared to both the IEEE Annual survey and Staff's Mid-Atlantic SAIDI chart, shows how unreasonable DPA's "gold plating" allegation is.

93 American Society of Civil Engineers, Economic Development Research Group, Inc. and LaCapra Associates, FAILURE TO ACT – The Economic Impact of Current Investment trends in Electricity Infrastructure, 2011 at p. 10. (A copy of this Report is attached to this brief as Opening Brief Att. 4). American Society of Civil Engineers, 2013 Report Card for America's Infrastructure, March 2013 at pp. 60 – 61. (A copy of this Report is attached to Delmarva's Opening Brief as Opening Brief Att. 3).

94 Executive Office of the President, Economic Benefits of Increasing Electric Grid Resilience to Weather Outages, August 2013. (A copy of this Report is attached to Delmarva's Opening Brief as Opening Brief Att. 2). Hoffman, Patricia (*Assistant Secretary of the U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability*), Keeping the Lights on for Americans: Modernizing the Nation's Electric Grid, Huffington Post, June 2, 2013. (A copy of this article is attached to Delmarva's Opening Brief as Opening Brief Att. 1).

third party reports and studies all reach the same conclusion: that increased reliability infrastructure investments must be made.[95]

C. Staff's Allegation That Delmarva Failed To Comply With Its Docket No. 11-528 Settlement Agreement Obligations Is Without Merit.

At pages 50 through 52 of its brief, Staff alleges that Delmarva failed to comply with its settlement obligations from its last base rate case, Docket No. 11-528. That argument is wholly incorrect. The pertinent obligations from the 11-528 settlement are as follows:

> "17. The Parties have agreed to meet and discuss several issues outside the confines of this rate proceeding in the hopes of resolving each of them. These issues include:
>
> (1) the establishment of metric(s) for the reporting and/or approval of reliability projects going forward so that customers are aware of how investment in Delmarva's plant in service benefits them in a quantifiable manner;
>
> (2) an agreement to meet and discuss alternative regulatory methodologies which would include, but not be limited to, multi-year rate plans."[96]

In other words, the parties agreed to meet and attempt to: (1) develop new reliability metrics for use in (a) reporting on reliability or approving reliability investments and (b) helping customers understand how reliability infrastructure (or "plant") investment benefits them and (2) develop a multiyear rate plan or other alternative regulatory methodology. This brief will hereinafter refer

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[95] DPA seeks to convince the Hearing Examiner that the ASCE *Failure to Act Report* is meant to "address the *national* grid, with a specific emphasis on *transmission*" (DPA Brief at pages 31-32, *emphasis original*). DPA's characterization of that report is mistaken. As the *Failure to Act Report* specifically states: "The focus of this report is on electricity, including generation, transmission, and the *distribution infrastructure* ..." (Report at page 3)(attached to Delmarva's Opening Brief as Opening Brief Att. 4). The Report further provides: "This report illustrates the importance of electric power generation, transmission and *distribution systems* to the national economy." (Report at page 4). "For the entire system to function, generation facilities need to meet load demand, transmission lines must be able to transport electricity from generation plants to local distribution equipment, and the decentralized *distribution networks* must be kept in good repair *to ensure reliable final delivery*." (Report at page 46). A review of the Failure to Act Report proves that it is focused on the system: generation, transmission and distribution. DPA's assertion that the Report has an emphasis on transmission is without merit.

[96] Paragraph 17 of Settlement Agreement in Docket No. 11-528 – approved by Commission Order No. 8265 (Dec. 18, 2012).

to these two settlement obligations as the "Reliability Metrics Obligation" and the "Multiyear Rate Plan Obligation."

In its Brief, Staff asserts that because Delmarva's policy witness, Mr. Boyle (the Chief Financial Officer of the Company) and Mr. Maxwell (the Company's reliability engineering and planning witness), were not personally aware of specific meetings where Delmarva worked to fulfill its Reliability Metrics and Multiyear Rate Plan Obligations, Delmarva must have failed to fulfill its settlement obligations.[97] As the actual facts reveal, however, Staff's assertion that Delmarva did not act to fulfill its Reliability Metrics Obligation is entirely incorrect.

At no point in any prefiled testimony, discovery, or any other prehearing activities did Staff raise the issue of meetings between Delmarva, Staff and DPA for the purpose of complying with the Reliability Metrics Obligation. When asked about this issue for the first time on Cross examination, Mr. Boyle stated that he "ha[d] not participated personally in any meetings."[98] Mr. Boyle also made clear that his understanding is that meetings between the parties concerning the Reliability Metrics and Multiyear Rate Plan Obligations did occur.[99] Mr. Maxwell also testified at the hearings that he did not participate personally in meetings with Staff where the Reliability Metrics and Multiyear Rate Plan Obligations were discussed.[100] Mr. Maxwell testified on cross that "[Delmarva] would be providing reliability benefits as part of the Forward Looking Rate matter."[101]

Witnesses Boyle and Maxwell are <u>not</u> the individuals at Delmarva involved in what have been extensive efforts by Delmarva, including numerous meetings between Staff, the Public Advocate and the Company, involving the Reliability Metrics and Multiyear Rate Plan

[97] Staff Brief at pages 50-51.
[98] Boyle hearing transcript at page 270, ln 15-16.
[99] "my understanding and general knowledge [is] that the follow up, as it relates to these issues, had occurred between the parties." Boyle hearing transcript at page 271, ln 5-7.
[100] Maxwell Hearing Transcript at page 310, ln 16-18.
[101] *Id.* at ln 7-10.

Obligations. Although the record in this docket does not contain facts concerning the extensive efforts by Delmarva to meet its Reliability Metrics Obligation, the publicly available filed application and testimony in another docket (the Forward Looking Rate Plan – Docket No. 13-384 or "FLRP") does address those facts.

As the testimony of Delmarva's Regional Vice President, Glenn Moore, in the FLRP Docket establishes, Delmarva began meeting informally with the Public Advocate and Staff to discuss the general design concepts of an FLRP within weeks after the Commission approved the settlement in Docket No. 11-528. Those discussions spanned several months and included a number of issues, including the development of more stringent minimum reliability performance metrics.[102] Mr. Moore's filed FLRP testimony provides that a key principle of the FLRP includes "Adopting more stringent reliability performance standards [i.e., 'metrics'] backed by consequences for not meeting those standards."[103] As that FLRP testimony further provides:

> The Company agrees to the establishment of *more stringent minimum reliability standards* [i.e., "metrics"]: a SAIDI that is 35% more stringent than the current Docket 50 minimum performance standard in year one and becomes more stringent in each of the three subsequent years of the four year FLRP rate effective period.... The Staff has made it clear that Delmarva's customers need to see a *quantifiable benefit from the investments Delmarva is making to maintain and enhance the reliability of its system*. Delmarva agrees with Staff and as such, developed the FLRP with these more stringent minimum mandatory reliability [metrics], backed by bill credits to customers if Delmarva fails to meet the stricter reliability standards. .[104]

Within weeks after the Settlement agreement in Docket No. 11-528 was approved by the Commission, Delmarva began extensive efforts towards meeting its settlement obligations – efforts that included numerous meetings and conversations with the Public Advocate and various

[102] Excerpts from testimony of Glenn Moore, Forward Looking Rate Plan filing, Docket No. 13-384, pg 5, ln 5-15 (attached hereto as "Att. 4").
[103] Id. at pg 6, lns 15-16.
[104] Id. at pg 28, ln 6-18. (*emphasis added*).

members of Staff.[105] Delmarva's efforts towards fulfilling its Docket 11-528 settlement obligations not only included numerous meetings, but included the substantial time and effort that went into developing, drafting and filing the FLRP Application and the supporting testimonies of three witnesses. Staff's assertion that Delmarva failed to comply with any settlement obligation, including the Reliability Metrics Obligation, is entirely without merit.

III. DELMARVA'S PROPOSED RETURN ON EQUITY IS REFLECTIVE OF MARKET CONDITIONS.

Delmarva premised its proposed return on equity (ROE) in this proceeding on its ROE Modeling and the prevailing market conditions. This is proper under both the applicable law as cited by the parties and this Commission's recent deliberations with respect to ROE. Staff and DPA both criticize the Company's methodology, and assert that it is inflated to produce high results.[106] Delmarva respectfully disagrees, and maintains that its analysis correlates with the current market conditions and accounts for the realities of the market.

First, it should be noted with respect to the ROE Modeling, Staff asserts that "under weighting the results of the DCF model is something [the Commission] does not support, and that the Commission's preference for using the DCF model is 'quite clear.'"[107] Delmarva recognized the Commission's continued reliance on the DCF model in its Opening Brief.

[105] The fact that many of those meetings and conversations (over a dozen) were between Mr. Moore and the former Public Advocate (Mr. Sheehy) and the former Executive Director of Staff (Mr. Obrien), and did not involve Staff's counsel, does not mean that those meetings and Delmarva's efforts did not occur - nor does it mean that anyone is free to represent to the Commission or the Hearing Examiner that they did not.

[106] Staff and DPA also attack the credibility of Company Witness Hevert by citing to other state commission decisions that have, reportedly, disagreed with the recommendations of Company Witness Hevert. As Company Witness Hevert testified at the evidentiary hearing "it is very unusual for a Commission to take any one specific [recommendation]' and other commission decisions have fallen within his recommended range. Tr. at 455:24 - 456:1 and 457:4 - 13. Moreover, many of the decisions in the recent Pepco case were consistent with Company Witness Hevert's recommended ranges. Certainly, other commissions and administrative law judges have determined ROE amounts that align more closely with Company Witness Hevert's recommendations than the other ROE witnesses presented, including the ROE witness relied upon by Staff and DPA. *See, e.g.* In Re: Petition of Atlanta Gas and Light Company for Approval of Adjustment of its Rates and Revised Tariff, State of Georgia Docket No. 31647, Final Order, pages 12-15 (October 27, 2010). The credibility assertions and rhetoric of Staff and DPA should be given no weight, and this proceeding should be decided on its merits, not the language used by another state's regulatory body.

[107] Staff AB at 24.

However, Delmarva disagrees that the Commission's preference is as "clear" following its decision in Docket No. 09-414, in which it found convincing non-DCF modeling analysis and also considered "the realities of the market" in setting the ROE.[108] In this proceeding, neither the DPA's nor Delmarva's ROE witness gave particular weight to its DCF model over another model.[109]

Second, with respect to the market conditions, DPA claims that "utilities are performing quite well" and asserts that there is no support for the conclusion that utility stocks underperformed the broad market from May 2013 to September 2013.[110] This is incorrect. Chart 3 in Company Witness Hevert's Rebuttal Testimony shows that during that period the S&P 500 gained 3.18%, while the proxy groups used by the ROE witnesses lost 12.49% and 7.82% respectively.[111] The reason the utility sector under-performed is the increase in interest rates and the increase in relative risk.[112] Further, the chart contained on page 131 of DPA's Answering Brief supporting the performance of utilities ends in 2012, before the run-up in interest rates as described and shown by Company Witness Hevert.

Staff asserts that "interest rates have remained low and continue to be historically low. Thus, low interest rates (and low CAPM results) are not temporary, but rather reflect investors' current expectation."[113] This statement is contrary to DPA Witness Parcell's agreement at the evidentiary hearing that interest rates are up since November 2012 (a month before the settlement of the Company's last rate case was approved by the Commission) and his recognition that the "flight to safety" reference in his direct testimony was no longer a major factor in the

[108] PSC Order No. 8011 ¶¶ 285-287.
[109] DPA AB at 131.
[110] DPA AB at 130 -131.
[111] Exh. 18: Hevert Rebuttal at 6:5-7 and 7: Chart 3.
[112] *See id.* at Chart 4.
[113] Staff AB at 33.

market.[114] Further, market-determined forward rates indicate that investors expect interest rates to increase.[115]

Next, Staff and DPA both assert that Company Witness Hevert's recommendations in this proceeding are inconsistent with the recommendation he made in PSC Docket No. 11-528.[116] That assertion is incorrect. There are many variables that affect ROE Modeling and an overall ROE recommendation, and not one of them can be relied upon in isolation. Company Witness Hevert recognized at the evidentiary hearing his belief that interest rates and the cost of equity generally are directionally related and move together, but that the degree to which they move together can change and they do not move in lockstep.[117] He also identified that during the period under consideration in PSC Docket No. 11-528 interest rates were volatile, beginning "fairly high" and falling during the period.[118] Thus, when volatility and uncertainty were high, investors fled to Treasury securities during the period, bidding up the price and down the Treasury yield.[119] The fact that Company Witness Hevert's recommendation is lower in this proceeding simply reflects the basic market reality that the lower Treasury yield was indicative of higher, not lower risk. In addition, interest rates are now rising, and the cost of equity moves together with Treasury yield as reflected in Company Witness Hevert's analysis.

Staff also appears to criticize Company Witness Hevert for the use of vertically integrated utilities in his proxy group.[120] Of course, DPA Witness Parcell also used vertically integrated utilities in his proxy group, as recognized by DPA in its Answering Brief.[121] DPA goes on, however, to state that Delmarva has less risk and therefore would not command as high

[114] Tr. at 484:12-22 and 473:5-18 (Parcell Cross).
[115] Exh. 18: Hevert Rebuttal at 5:3-6 and 6: Chart 2.
[116] Staff AB at 44; DPA AB at 119.
[117] Tr. 429:2-13 (Hevert Cross).
[118] Id. at 425:24 - 426:3.
[119] Exh. 3: Hevert Direct at 18-20.
[120] Staff AB at 35-36.
[121] *See* Exh. 15: Parcell Direct at Exhibit DCP-6.

a ROE as companies with generation - "a fact that Mr. Parcell recognized but Mr. Hevert seems not to."[122] At the evidentiary hearing, Company Witness Hevert discussed the risk reflected by the market with utilities and specifically Southern Company's risk.[123] Notwithstanding that Southern Company is a vertically integrated utility, which has coal plants and is developing a nuclear plant, it still has the lowest Beta coefficient in either of the ROE witnesses' proxy groups.[124] Thus, the risk as considered by the market is not as directly determined as suggested by DPA.

Lastly, Staff asserts that Company Witness Hevert relied on only "the highest growth estimates (and only one estimate - i.e., Value line, or First Call, or Zacks) to determine the projected growth in his DCF calculations.[125] This is factually incorrect. Company Witness Hevert calculated the mean, the mean-low, and the mean-high.[126] While Staff is focused on the mean-high result, ranging from 11.63% to 11.71%, this is approximately 90 basis points above the high end of Company Witness Hevert's final recommended range. Similarly, Staff asserts that Company Witness Hevert's analysis is influenced upward by the inclusion of two companies, Otter Tail Company and PNM Resources, that have growth rates "far exceeding" those of other proxies.[127] Again this is factually inaccurate. Company Witness Hevert specifically excluded Otter Tail Company growth rate from his DCF analysis as it was "more than two standard deviations from the unadjusted mean growth rate."[128] Thus, it is unsupported to state that his analysis was focused on methods and data to produce the "highest possible results" or "cherry picking."

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[122] DPA AB at 121.
[123] Tr. at 443:6-445:3.
[124] See Exh. 15: Parcell Direct at Exhibit DCP-6.
[125] Staff AB at 41.
[126] Exh. 3: Hevert Direct at 14: Table 2.
[127] Staff AB at 43.
[128] Exh. 18: Hevert Rebuttal at 18:11-15.

The ROE Modeling results and analysis presented by Company Witness Hevert support the Company's proposed 10.25% ROE. Company Witness Hevert adjusted his analysis to reflect recent changes in current and expected market conditions thus presenting an analysis that correlates with current market conditions and is sensitive to market realities. Accordingly, the Company's proposed ROE should be adopted by the Commission.

IV. DELMARVA'S PREPAID PENSION ASSET BENEFITS ITS CUSTOMERS AND THE COMMISSION'S PRECEDENT IN ALLOWING SUCH ASSETS IN RATE BASE SHOULD BE FOLLOWED.

DPA makes several assertions in its Answering Brief that it believes support a reversal of this Commission's prior decision's allowing prepaid pension assets and OPEB liability to be included rate base, including: (1) that the Company's prepaid pension asset and OPEB liability are not "used and useful in the provision of utility service." and (2) that the Company "cannot satisfy its burden of establishing that shareholders, rather than ratepayers or the market, contributed the funds comprising them."[129]

This Commission recognized in PSC Docket No. 05-304 its belief "that the pre-paid pension asset is appropriately included in rate base because it is caused by a negative pension expense, which both reduces base rates, resulting in rates that are lower than they otherwise might be, and at the same time creates a cash working capital requirement."[130] It also expressly recognized that "the Company has no access to this asset to use for other operating expenses" and "is precluded by federal law from using any of the money it has collected for pensions for any other purpose."[131] Yet, it is upon these two express recognitions that DPA now seeks to assert that the Company's pre-paid pension asset is not "used and useful."[132]

[129] DPA AB at 53.
[130] PSC Order No. 6930 ¶ 58.
[131] *Id.*
[132] DPA AB at 54.

DPA improperly asserts the "used and useful" standard as contained in the statutory definition of "rate base." The Commission was correct to recognize the benefits of a pre-paid pension expense in PSC Docket No. 05-304. As explained by Company Witness Ziminsky:

> The existence of a Prepaid Pension Asset on the Company's balance sheet indicates that the Company's cash contributions and return in the pension trust exceed the accumulated benefit obligation. This being the case, the pension trust's assets are higher than they otherwise would be, which increases the expected return on assets. The increase in the expected return on assets because of the existence of a Prepaid Pension Asset decreases the Company's pension expense, all things being equal. The decrease in the Company's pension expense due to the existence of the Prepaid Pension Asset decreases the Company's cost of service.[133]

DPA referenced the Company's response to its "on the record data request" in its Answering Brief.[134] As Company Witness Ziminsky explained in this response with respect to the 2012 test period cost of service, absent pension plan returns, the overall pension expense level would have increased by $4.682 million, or 42%. Thus, the Prepaid Pension Asset is useful to customers, as it results in rates that are lower than they would otherwise be calculated if there was no such asset.

In its brief, DPA cites extensively to the *Re Central Telephone Company of Texas* matter, as decided by the Texas Public Utility Commission, in support of its assertion that this Commission was incorrect in its decision in PSC Docket No. 05-304.[135] A review of recent Texas Public Utility Commission decisions indicates, however, that the Texas Commission no longer follows that decision as precedent. In 2008, the Texas commission allowed a pension asset that included investment income to be part of rate base.[136] More recently, the Texas

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[133] *See* Ex. 20: Ziminsky Rebuttal at 72:7-14.
[134] DPA AB at 55, fn. 47.
[135] DPA AB at 57-60.
[136] Public Utility Comm'n of Texas, Application of AEP Texas Central Company for Authority to Change Rates, Docket No. 33309, Final Order ¶¶ 25-32 (March 4, 2008)(attached hereto as "Att. 5").

Commission allowed a prepaid pension asset to be included in rate base in 2012.[137]

Lastly, DPA asserts in its Answering Brief that the Company has a burden to show that the prepaid pension asset was solely funded by the Company, relying on three cases from outside of Delaware. Those cases, however, do not deal with prepaid pension assets and are inapposite. Moreover, the entire asset offsets current pension expenses to the benefit of ratepayers. Thus, this Commission was correct in PSC Docket 05-304 to allow the Company's prepaid pension asset in rate base. That precedent should be followed in this current case.[138]

V. DELMARVA'S SERP EXPENSES ARE NECESSARY AND SHOULD BE INCLUDED AS PART OF THE COMPANY'S REVENUE REQUIREMENTS.

This Commission approved the inclusion of SERP expenses in the Company's cost of service in PSC Docket 09-414.[139] In doing so, the Commission agreed that the benefits were "necessary to attract and retain executive talent," and that these benefits were "true retirement benefits," not executive incentive payments.[140] While the Company seeks to follow this precedent and include SERP expenses in this proceeding, DPA opposes this inclusion on the grounds that "times have changed."[141] Staff also opposes the inclusion for the first time in its

[137] Public Utility Comm'n of Texas, Application of Entergy Texas, Inc. for Authority to Change Rates, Reconcile Fuel Costs, and Obtain Deferred Accounting Treatment, Docket No. 39896, Order pg. 2 (September 14, 2012)(attached hereto as "Att. 6").

[138] On February 3, 2014, Staff filed a document entitled "*Joinder of the Staff of the Public Service Commission to the Division of the Public Advocate's Arguments in its Post-Hearing Answering Brief Regarding Prepaid Pension Asset*" ("Staff's Joinder"). In Staff's Joinder, Staff seeks to join the DPA's argument against Delmarva's Prepaid Pension Asset. Nowhere in evidentiary record in this case does Staff contest or question the Commission's precedent of including prepaid pension assets in rate base. Staff's Post Hearing Brief was due and was filed on January 21, 2014. Staff's Joinder, filed on February 3, 2014, was filed out of time and attempts to both change Staff's position on the Prepaid Pension Asset and assert additional legal argument after Staff's brief was due. For example Staff's Joinder argues that that DPA provides: "persuasive arguments and compelling case law…." (Staff's Joinder at ¶ 3) In addition, citing a Hawaii decision that contradicts the Delaware Commission's precedent, Staff further argues that "where market earning contribute to the majority of the current pension fund balance, ratepayers should not be charged again for a return on rate base for assets that investors have not actually supplied." (*Id.*). Staff's Joinder should be stricken as an out of time attempt to provide additional written argument that changes Staff's position on a significant issue in this case.

[139] PSC Order No. 8011 at ¶ 184.

[140] *Id.*

[141] DPA AB at 84.

Answering Brief.[142]

The Commission's decision in Docket 09-414 was made on August 9, 2011. All of the other commission decisions cited to by the DPA in support of its opposition to SERP expenses were decided before that decision. Further, as identified by the Company in its Opening Brief, the facts surrounding its SERP expenses have not changed since then, and the benefits are part of recruiting and retaining executives for the Company. Company Witness Boyle testified to this at the evidentiary hearing.[143] Thus, this Commission's precedent, allowing SERP expenses as part of the Company's cost of service, should be followed in this proceeding. There are simply no facts of record in this case to suggest that Delmarva's SERP program constitutes "waste, inefficiency or bad faith."[144]

VI. THE COMMISSION SHOULD ALLOW THE COMPANY'S CONSTRUCTION WORK IN PROGRESS (CWIP) TO BE PART OF RATE BASE AS IT IS NECESSARY FOR DAY-TO-DAY BUSINESS AND OPERATIONS.

Staff and DPA assert that CWIP should not be included in the Company's rate base because it is not "used and useful" during the test period.[145] Staff's argument ignores the fact that the projects in CWIP were either used and useful during the test year, and those that were not, will be used and useful during the rate effective period. From the filing of its initial testimony, Delmarva has been clear that it is seeking a change from the Commission's most recent precedent regarding CWIP.[146] As the Commission specifically noted in Order No. 6930, until that Order, it had "permitted Delmarva to include CWIP in rate base since at least 1984."[147] The Commission stated that it "retain[s] the discretion to include or exclude CWIP from rate

[142] Staff AB at 81.
[143] Tr. at 283:19-22 (Boyle Cross).
[144] *Delmarva Power*, 508 A.2d at 859.
[145] Staff AB at 58-59; DPA AB at 47.
[146] Ziminsky Direct at 8.
[147] Order No. 6930 at ¶ 47.

base based on the facts presented in each individual case.[148] In this case, Delmarva is asking the Commission to exercise its discretion to include CWIP in rate base.

First, the Company maintains that the plant projects reflected in CWIP, which is comprised of short-term projects that close to plant on a daily, weekly or monthly duration, were either used and useful during the test period or will be during the rate effective period. These projects are known and reasonable, and inclusion of the CWIP in rate base is necessary for rates to be reflective of the cost of assets used to provide service to customers during the rate effective period.

Second, Staff and DPA both cite to the statutory definition of "rate base" for the "used and useful" during the test period standard. The "rate base" definition, however, does not limit itself to only "used and useful" plant during the test period. The definition defines "rate base" as:

> a. The original cost of all used and useful utility plant and intangible assets either to the first person who committed said plant or assets to public use or, at the option of the Commission, the first recorded book cost of said plant or assets; ....
>
> plus ...
>
> g. Any other element of property which, in the judgment of the Commission, is necessary to the effective operation of the utility.[149]

The Commission's Minimum Filing Requirements do not recognize CWIP as being part of "rate base" under subsection (a) above, which contains the "used and useful" standard, but instead include it as an "other element of property" of rate base.[150] As described above, the CWIP carried by the Company on its books is not for the major projects that could be carried for a period of years without being necessary for the then-current business or operations, but is part

[148] *Id.*
[149] 26 *Del. C.* § 102(3).
[150] *See* 26 *Del. Admin. C.* 1002 § 4.11; see also Exh. 1, Schedule No. 2

of the Company's day-to-day business and operations. As such, they are proper within the Company's "rate base." The inclusion of CWIP is necessary to make rates reflective of the cost of providing service during the rate effective period and for this reason, Delmarva respectfully requests that it be included in rates.

As another option to Delmarva's proposal of including CWIP in rate base, Delmarva proposed an alternative using a regulatory asset.[151] Although this alternative is opposed by Staff and DPA, the Company maintains that it is a viable alternative to address the inclusion of CWIP in its cost of service.

VII. <u>DELMARVA'S INCENTIVE COMPENSATION PROGRAM BENEFITS CUSTOMERS AND IS NOT IN PLACE TO INCREASE SHAREHOLDER DIVIDENDS.</u>

Staff seeks to remove all non-executive incentive compensation as part of the Company's revenue requirements.[152] DPA also opposes the inclusion of these costs in revenue requirement, going so far as to ask/answer:

> "What really are the benefits to ratepayers of employees meeting the safety, customer service, reliability and other non-financial goals, and how does meeting them benefit ratepayers? Savings that accrue between rate cases benefit shareholders, because rates are not adjusted in between cases to reflect such savings.[153]

This is a fundamental disconnect between Delmarva and DPA; Delmarva does not view its customers as simply "ratepayers" and believes that there are more elements to providing its services than just the rates that customers pay. These include safety, customer service, customer satisfaction, reliability and financial management, for which the Company sets goals to achieve. The Company's annual incentive plan (AIP) helps to focus employees' attention and efforts on achieving performance goals, many of which are explicitly related to safety and customer

[151] *See* Exh. 5: Ziminsky Direct at 32:18-33:12.
[152] Staff AB at 73.
[153] DPA AB at 80.

service. Accordingly, the AIP establishes a framework by which incentive compensation is paid.[154]

Further, as set forth in the Company's Opening Brief, Company Witness Boyle explained the importance of incentive compensation in attracting and keeping skilled employees.[155] He described that incentive compensation is consistent with peer practices, and that he was not aware of a single company in the industry that doesn't offer annual incentive plans.[156] Company Witness Boyle also explained that including financial targets in the AIP is not designed to simply increase profits, but also lowers the costs that will be in the Company's cost of service (by both operating expenses and the Company's financial metrics).[157]

Staff contends that the Company's threshold earnings requirement as incorporated into the Company's AIP demonstrates that the "paramount goal of the AIP is to increase shareholder divided income."[158] DPA makes a similar argument.[159] These arguments are refuted in the record. Company Witness Boyle explained at the evidentiary hearing that including financial targets in the AIP is not designed to simply increase profits, but also lowers the costs that will be in the Company's cost of service (by both operating expenses and the Company's financial metrics).[160] He explained that Delmarva uses its incentive plan to drive certain performance that it views as focal areas, such as reliability and safety.[161] Company Witness Ziminsky further explained that the financial triggers also serve to "ensure that the incentives, one, can be paid out of earnings and don't jeopardize the Company."[162] Staff and DPA's assertion that the goal of the

[154] Exh. 5: Ziminsky Direct at 35:1-6.
[155] Exh. 17: Boyle Rebuttal at 10:5-7; Tr. at 201:19-24 and 2021-6 (Boyle Cross).
[156] Tr. at 201:21-24 and 202:1-6 (Boyle Cross).
[157] Exh. 17: Boyle Rebuttal at 11:2-9.
[158] Staff AB at 75.
[159] DPA AB at 80.
[160] Exh. 17: Boyle Rebuttal at 11:2-9.
[161] Tr. at 205:21-24, 205:16-23 (Boyle Cross).
[162] Tr. at 693:3-8 (Ziminsky Re-direct).

AIP is to increase shareholder dividend income is unsupported and the record in this proceeding amply supports the inclusion of non-executive incentive compensation as a revenue requirement.

Delmarva has offered significant evidence that the AIP benefits customers and that incentive programs are both valuable and routinely used across the utility industry to achieve the best results out of utility employees. There is no evidence that Delmarva's AIP constitutes "waste, inefficiency or bad faith."[163] Accordingly, Delmarva requests that the Hearing Examiner follow Commission precedent from prior to PSC Docket No. 05-304 and recommend that non-executive incentive compensation be included as an element of Delmarva's revenue requirement.[164]

VIII. <u>DELMARVA'S USE OF YEAR-END RATE BASE IS PROPER UNDER THE COMMISSION'S MFRS.</u>

In this proceeding, Delmarva developed its revenue requirement using the year-end balances on its books. The Company determined that, given the scenario at the time of the Application in which rate base was growing and revenue growth was not keeping pace, the use of year-end rate base better reflected the rate base that would be representative of the rate effective period.[165] Staff advocates that the Commission set Delmarva's revenue requirement by using an average rate base, asserting that the Company's use of year-end rate base "overstates the revenue deficiency by understating the income capacity of the existing rates."[166]

The Company's use of year-end rate base should be approved by the Commission. The

[163] *Delmarva Power*, 508 A.2d at 859.

[164] *See* PSC Order No. 8011 ¶ 194. In Docket No. 09-414, this Commission denied the Company's proposal for lack of evidence as to the amount of compensation attributable to the achievement of safety, reliability and customer service goals. Delmarva quantified the component allocation of the total non-executive incentive compensation in this proceeding. Exh. 5: Ziminsky Direct at 36:3-6.

[165] *See* Exh. 20: Ziminsky Rebuttal at 85:10-13.

[166] Staff AB at 47. The discussion of this issue in Staff's brief is a representative example of the rhetoric and mischaracterizations in the brief. Staff states: "The Company explains this change in test year philosophy in just three (3) lines of testimony from a witness who has never testified on the subject before." Staff forgets that the Company submitted approximately 4 pages of testimony discussing its use of year-end rate base in its rebuttal testimony. *See* Exh. 20: Ziminsky Rebuttal at 82-85. Further, the number of times that Company Witness Ziminsky has testified before the Commission with respect to a particular issue is meaningless.

Commission's Minimum Filing Requirements allow the use of year-end rate base in calculating a public utility's revenue requirements.[167] Further, the Company adjusted its revenues to include an annualization for its year-end customer counts, as well as an annualization of depreciation expenses for year-end plant balances, including test period reliability plant closings.[168] These adjustments were done to ensure that revenues and depreciation expense properly matched the year-end rate base.[169]

The combination of increasing rate base and lower revenue growth results in regulatory lag that has contributed to the Company's under earning over recent years.[170] Accordingly, the use of year-end rate base is appropriate in this proceeding to reflect a rate base that will be representative of the rate effective period.

IX. CLASS COST OF SERVICE

A. The Company's Proposed Class Cost of Service Study is Just and Reasonable and Should be Used for Setting Class Revenue Requirements and Class ROR

In developing its Class Cost of Service Study (CCOSS), contrary to the arguments made by Commission Staff, the Company did not disregard cost causation principles. As stated by Company Witness Tanos, "The fundamental principle underlying the cost allocation process is that costs should be attributed to the particular customer groups that cause the utility to incur such costs". [171] The Company has carefully evaluated each line item of the CCOSS: rate base, revenues, and expenses to appropriately allocate the particular item based upon the underlying principle of cost causation. Appropriately allocated costs then provide a basis to derive class rate of return results and class revenue targets, and they serve as an important guide in designing the

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[167] *See* 26 *Del. Admin. C.* 1002 § 3.1.1.
[168] Exh. 20: Ziminsky Rebuttal at 82:12-14.
[169] *Id.* at 82:16-18. Additionally, in calculating average rate base, Staff Witness Peterson failed to annualize test period reliability closings as recognized by this Commission in PSC Docket Nos. 05-304 and 09-414.
[170] *Id.* at 85:4-6.
[171] Exh. 8: Tanos Direct at 4:6-8.

rates charged to each customer class. Delmarva's proposed CCOSS is just and reasonable and should be used as a basis for setting customer class revenue requirements and class ROR in this proceeding.

B. The Cost Allocation Approaches Applied in the CCOSS are Equitable and Reasonable and Should be Retained

The cost allocation approaches used in the Company's CCOSS are consistent with the methods used in the filings in Docket Nos. 05-403, 09-414, and 11-528, that served as the foundation or starting point for the approved rate design in those cases. In this proceeding, the CCOSS also incorporates the results of the initiatives stemming from the CCOSS workshop held in compliance with Order No. 8011 in Docket No. 09-414, for consideration by the Commission.[172]

1. The Demand Allocation Methods used in the CCOSS Reflect Load Diversity

For decades, the electric distribution industry has applied standard demand measures for cost allocation purposes that reflect load diversity considerations. These demand measures are described in the NARUC Electric Utility Cost Allocation Manual (NARUC manual) on page 97.[173] The Company has applied these standard demand measures in the development of the demand allocation factors used in its CCOSS for this case. The NARUC manual further explains that load diversity at distribution substations and primary feeders is usually high and facilities nearer the customer, such as secondary feeders and line transformers, have much lower load diversity. Along this diversity continuum, the levels of the demands for each class and the actual point for each customer will be different.[174]

In the CCOSS, the primary distribution system plant costs that comprise the majority of

[172] Exh. 8: Tanos Direct at 7:20-8:21.
[173] The NARUC manual identifies the two demand measures: customer-class noncoincident (diversified) demands and individual customer maximum (non-diversified) demands.
[174] Exh. 22: Tanos Rebuttal at 3:23-4:4.

Delmarva's distribution plant investment (including substations and primary lines) are allocated using the class maximum diversified demands, reflecting the diversified demands served by these facilities.[175] The secondary plant cost allocators recognize that equipment, such as line transformers, may serve multiple customers so that the diversity of load will impact the sizing of the transformer. Other transformers serve a single customer so no load diversity is considered in sizing that equipment. Company Witness Tanos pointed out that the very large secondary customers generally will have their own transformer at their facility and are generally not adjacent to other large customers. Smaller customers have much smaller loads and are often more clustered, which provides for the aggregation of several customers for sizing and installing transformers.[176]

To reasonably reflect these conditions in developing the allocation of line transformer costs, the CCOSS first isolated the larger secondary customers and allocated line transformer costs to this class based solely on the customer maximum non-diversified demands. Next, the remaining line transformer costs were allocated to all other secondary customers using the 50/50 weighting of class diversified demands and customer maximum non-diversified demands. The 50/50 weighted demand approach recognizes the aggregation described above and is a reasonable and manageable approach to achieve a further allocation of these costs. Using only one of the demand approaches (either class demands or customer maximum) would under allocate (class demands) or materially over allocate (customer maximum) costs to smaller customers, such as residential. The magnitudes of these demands by customer class are clearly shown on page 18-2 of Schedule (EPT)-1. The only proper use of the customer maximum

[175] Exh. 22: Tanos Rebuttal at 2:19-3:2.
[176] Exh. 22: Tanos Rebuttal at 4:9-15.

demands is in the allocation with respect to large secondary customers.[177] The Company's CCOSS applies a realistic and manageable 50/50 weighting of the class maximum diversified demand and customer maximum demands by class as the most reasonable and practical approach by far to achieve a fair allocation of these costs.

Delmarva considers load diversity when designing facilities and sizing equipment to meet customer demand and to efficiently make investment in the required equipment.[178] The Company also conducts detailed analyses of the respective demands for each customer class in the preparation of each cost study submitted to the Commission.[179] This combined experience with the operation of the Delmarva Delaware distribution system and the analyses of demands by customer class, together with review of industry best practices, are the basis for the selection and development of the cost allocation approaches used in the CCOSS.

Staff Witness Pavlovic has not provided any credible analysis, evidence, or alternatives for the Company's CCOSS, yet he professes that it is fatally flawed and should not be used to distribute the revenue requirement for rate design purposes. Witness Tanos provided evidence that the vast majority of the applicable distribution plant costs (about 80%) are allocated based on a highly diversified demand allocator[180] – not zero diversity, as initially asserted by Staff Witness Pavlovic,[181] and that the existing structure of the CCOSS demand allocation factors produce reasonable class results[182] Including the secondary plant allocators (blended demand allocators). Staff Witness Pavlovic's apparent lack of understanding of even the basic structure of the demand allocators used in the CCOSS is reason alone to reject his assertions regarding the

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177 Exh. 22: Tanos Rebuttal at 4:16-23.
178 Exh. 22: Tanos Rebuttal at 3:9-11.
179 Exh. 8: Tanos Direct at 9:16-10:9; Exh. 22: Tanos Rebuttal at 2:8-5:5.
180 Exh. 8: Tanos Direct Attached Schedule (EPT)-1 at 2:1-23. The "ALLOC" column identifies the allocation approach.
181 Exh. 10: Pavlovic Direct at 13:15-14:1.
182 Exh. 22: Tanos Rebuttal at 7:20-23.

load diversity embodied in those allocators.[183]

The Company's cost allocation approaches are: (1) consistent with the CCOSS filings in Docket Nos. 05-304, 09-414, and 11-528; (2) based on experience with the Delaware distribution system and ongoing detailed analyses of demands by each customer class; and (3) recognized generally in the electric industry. In addition, to further refine the process now that the AMI meters have been deployed within its service territory, the Company is developing a process to integrate the new AMI metered data to prepare the demand measures used in the CCOSS. Witness Tanos explained that the Company has recently started to use the AMI data from residential and small commercial class services in the Load Settlement process.[184] Once a full year of load data has been collected through this process, the Company will be able to determine the CCOSS class maximum diversified loads and a full year of customer hourly demands will also have been collected for analysis.[185]

2. Delaware Underground/Overhead System Cost Assignment

Staff Witness Pavlovic argues that Delmarva's underground and overhead system costs are not allocated appropriately because commercial customers generally make greater use of underground facilities than residential customers.[186] However, he has not conducted any study or analysis whatsoever of the Delaware distribution system to support his assertions.[187] In fact, for the past forty-three years, Delaware law has required that regulated electric distribution companies provide underground facilities for all new extensions of electric services for new residential subdivisions of greater than five (5) lots and for multifamily buildings. [188] Every new

[183] In Direct Testimony, Staff's CCOSS expert may have confused the demand allocators, with the demand measures used in the CCOSS.
[184] Exh. 22: Tanos Rebuttal at 6:8-11.
[185] Exh. 22: Tanos Rebuttal at 6:13-18,
[186] Exh. 10: Pavlovic Direct at 12:20-13:3.
[187] Tr. at 965:4-17.
[188] 26 *Del. C.* § 901(c).

residential subdivision in Delaware is installed with underground facilities, and new homes are predominately planned subdivisions.[189] Some recent construction data was also presented to highlight this long term (multi-decade) trend.[190] Because Staff Witness Pavlovic's opinion is based upon unsubstantiated assertions that are not supported by the evidence, it must be rejected.

Witness Pavlovic recommends that the Advanced Metering Infrastructure (AMI) data and the Geospatial Information System (GIS) should be used to develop CCOSS demand allocators to be submitted in Delmarva's next rate case.[191] Witness Tanos emphasized that such an initiative would require the interface of numerous major Company databases that are not linked, and would be highly complex and expensive for cost of service purposes.[192] Witness Tanos also emphasized that the Company's asset accounting system is not maintained at the level of detail needed for this request, and that the classification of customers itself under this proposal would introduce additional complexities for cost assignment. Therefore, Staff's recommendation should be rejected.

3. The CCOSS Workshop Initiatives are Reasonable, were accepted by the Parties and should be Approved.

The CCOSS developed for this docket includes certain initiatives undertaken as a result of the CCOSS workshop conducted after the conclusion of Docket No. 09-414 in accordance with the provisions of PSC Order No. 8011;[193] however, Staff argues that none of the parties agreed to the initiatives resulting from the CCOSS workshop.[194] The following initiatives were incorporated into the CCOSS as a result of the workshop: use of Delaware specific load survey

[189] Exh 22: Tanos Rebuttal at 5:21-6:4.
[190] Exh 22: Tanos Rebuttal at 5:21-6:4.
[191] Exh 10: Pavlovic Direct at 15:15-16-:4.
[192] Exh 22: Tanos Rebuttal at 6:22-7:15.
[193] The parties agreed to convene a workshop to address the CCOSS and revenue allocation issues in order to develop an agreement on a CCOSS approach to be used in future rate cases. PSC Docket No. 09-414, Findings and Recommendations of Hearing Examiner at ¶¶314-316.
[194] Staff brief at 93-94.

data to estimate residential non-coincident peak demand; use of weather normalized sales and revenue data; the development of a revised Account 369-Service line allocator; and the disaggregation of the traffic signal service form the general street lighting class.[195] Despite Staff's argument, they produced no witness or other evidence to corroborate their position nor did they argue against the merits of including these initiatives in the CCOSS. Both Company Witness Tanos and DPA Witness Dismukes testified that these initiatives were in fact agreed to by the parties,[196] and they should be adopted.

C. The Load Analysis Used to Develop the Demand Allocators is Reliable

Witness Dismukes recommends that the Commission adopt Delmarva's proposed CCOSS, subject to selected modifications. He lists the use of the most recently available analysis of class load data as being an example of "deficiencies in the Company COS methodology." [197] However, using demand allocators based on load studies from prior years is neither uncommon nor does it create significant reductions in the reliability of the allocators.

The Company has followed historical filing processes and has used the most recent load data available at the time of preparing the CCOSS. Witness Tanos detailed the processes required to complete the load analysis for cost of service purposes explaining that the load data was prepared annually on a calendar year basis and is compiled by supplier and customer class after the determination of the Delmarva zonal loads.[198] The system and class peak load data is then derived from a study of the prior calendar year retail load settlement hourly loads. The customer maximum demand has historically come from an annual analysis of all demand-metered class customer demand and energy readings for the calendar year, together with a ratio

[195] Exh. 8: Tanos Direct at 7:20-8:21.
[196] Tr. at 918:17-24 and 919:1-11 (Tanos Cross). Exh. 14: Dismukes Direct at 32:21.
[197] Exh. 14: Dismukes Direct at 32:21-33:4.
[198] Exh. 22: Tanos Rebuttal at 8:5-9.

analyses performed on twelve-months of the residential profile class survey data.[199] This process has been consistently followed and was used in both Docket No. 09-414 and Docket No. 11-528 in the preparation of the CCOSS.

As explained by Witness Tanos, the CCOSS serves as an important guide in the rate design process. Traditionally, the Company has prepared one class cost of service study that provides guidance in the rate design process for that case and produces reliable CCOSS results. DPA also challenged the Company's response to a data request regarding load research sampling.[200] The lead question in that data request asked how the Company developed the appropriate load research sample for customer classes without demand metering.[201] The next question in that data request asked for a listing of all statistical tests the Company has performed to verify the accuracy of its load research sample.[202] The Company's response detailed the steps involved and the many statistical tests originally undertaken to determine and validate the load research sample developed in 2008.[203] Witness Dismukes inferred from the Company's data responses that "[the Company] has not verified the validity of its load research samples since an analysis was conducted in April 2008..."[204] Witness Tanos explained, however, that the Company performs regular monthly checks of the sample statistical reliability as part of the monthly load profiling process for the Delmarva Zone final load settlement.[205]

The Company presented evidence showing that non-demand metered class non-coincident demands exceeded the statistical reliability design standards during peak months of

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[199] Exh. 22: Tanos Rebuttal at 8:9-14.
[200] DPA brief at 137.
[201] Exh. 90.
[202] *Id.*
[203] *Id.*
[204] Exh. 14: Dismukes Direct at 33:2-3.
[205] Exh. 22: Tanos Rebuttal at 8:20-22.

the last several years.[206] Furthermore, a set of sample validation tests like those originally performed for the sample design were performed and provide evidence that the sample data used for the customer maximum demands for the Residential Classes were valid and statistically reliable.[207] As Witness Tanos testified, the Company's load research sampling and analysis process is a very rigorous one to ensure accuracy.[208]

D. The Company's Use of Labor to Allocate General and Common Plant follows Cost Causation Principles and should be Retained

Witness Dismukes acknowledges that the Company's Labor allocator is similar in function to the use of operating labor ratios discussed in the NARUC Manual. [209] Moreover, upon questioning by the Company, Witness Dismukes clearly stated that there is nothing wrong with Delmarva's CCOSS method; rather, he believes that his proposal is more straight forward and less complex, and he simply prefers his methodology over that of the Company. [210]

As emphasized by Witness Tanos throughout these proceedings, the underlying principle guiding the development of Delmarva's CCOSS is cost causation.[211] The Labor allocator is applied to General and Common plant as well as to certain Administrative and General expense accounts that are labor-oriented or labor-based, including infrastructure that houses staff, and resources to meet personnel needs, including computers, communication equipment, and software that are used by personnel to run the system.[212]

The Company also applies the Labor allocator in the development of the CCOSS for Delmarva Delaware Gas, Delmarva Maryland, and the Atlantic City electric Company. Evidence was also presented that the labor ratio approach is recognized as an acceptable allocation method

[206] Exh. 22: Tanos Rebuttal at 8:20-9:13.
[207] Exh. 22: Tanos Rebuttal at 8:20-9:13.
[208] Tr. at 904:14-906:6.
[209] Exh. 14: Dismukes Direct at 34:20-21.
[210] Tr. at 538:22-539:23.
[211] Exh. 22: Tanos Rebuttal at 10:8-9.
[212] Exh. 22: Tanos Rebuttal at 10:14-18.

in the industry and by the FERC.[213]

E. The Company's Allocation Approach for Customer Information and Sales Expenses (FERC Account 907-913) is Fair and Reasonable and Should be Retained.

Witness Dismukes argues that Customer Information and Sales Expenses should be classified as customer-related, and then allocated based only on the number of customers.[214] The Company agrees with Witness Dismukes that the expenses included in FERC Accounts 907-913 should be classified as customer-related. In fact, the CCOSS does classify these expenses as customer-related as clearly shown in Schedule (EPT)-2, "CUSTOMER COMPONENTS".[215] However, as Company Witness Tanos established, the use of the number of customers alone to allocate the costs of Accounts 907-913 would assign the vast majority of the costs to essentially one class, Residential, based on total class population.[216] He further pointed out that the NARUC Manual describes the goals of the programs, such as conservation programs that include saving electricity on an annual basis, and for Sales Expenses (Account 913), and that the NARUC Manual suggests the use of a more general allocation scheme, rather than number of customers.[217] To provide a fair and representative approach, the Company prepared an equally weighted composite allocation based on the number of customers and their corresponding sales usage.[218] Finally, DPA's Brief mentioned parenthetically that the Company offered no rebuttal to Witness Dismukes' recommendation insofar as it applies to Accounts 914-917.[219] As clearly shown on Schedule (EPT)-1, page 9, the CCOSS does not use these expense accounts, e.g.,

[213] Exh. 22: Tanos Rebuttal at 10:19-22.
[214] Exh. 14: Dismukes Direct at 36:24-26.
[215] Exh. 8: Attachments to Tanos Direct. DPA's brief at 148-149 also references the NARUC Manual regarding Meter Reading Expenses (Account 902) and Uncollectible Accounts expense (Account 904). The Company performed separate studies to determine the allocation of Accounts 902-904 which are not allocated using blended customer and sales allocation factors.
[216] Exh. 22: Tanos Rebuttal at 11:8-10.
[217] Exh. 22: Tanos Rebuttal at 11:19-12:2.
[218] Exh. 22: Tanos Rebuttal at 11:12-16.
[219] Staff's Brief also references the NARUC manual regarding FERC Accts. 902-904 (not within Staff's discussion of accounts 907-913).

Account 917 is for non-Major Utilities only.[220]

F. DEUG's Proposal to Allocate Distribution Plant Accounts 364-367 on both a Demand and Customer Basis Should be Rejected

DEUG Witness Phillips agrees that the Delmarva CCOSS comports with generally accepted costs of service methods, but argues that certain distribution plant accounts currently classified as demand-related should be re-classified as customer-related.[221] Further, he supports the use of the Minimum Distribution System (MDS) analysis to determine this customer cost component. The Commission previously considered use of the MDS in Docket No. 05-304, and rejected it.[222] There has been no evidence presented of changed conditions in this proceeding such that would now cause the Commission to reconsider use of the MDS, and for the many reasons detailed in Witness Tanos' Rebuttal Testimony, DEUG's proposal should be rejected.

The Company's proposal to classify distribution poles, lines, and line transformers as demand-related, and to classify services and meters as customer-related, is consistent with the methods used in previous studies before the Commission and provides a reasonable classification of the customer-related cost components. The Company's approach is well-recognized in the industry and should be adopted.[223]

Delmarva's proposed CCOSS filed in this case is consistent with the Company's submissions in prior cases that were the starting point for the approved rate designs in those cases. The CCOSS also reflects the agreed initiatives from the CCOSS workshop and is building the processes to incorporate the new AMI data, as addressed previously. The CCOSS that the Company has submitted provides a just, reasonable and practical approach to achieve a fair allocation of costs to the respective customer classes and the Company respectfully requests that

[220] Exh. 8: Attachments to Tanos Direct.
[221] Exh. 16: Phillips Direct at 3:1-4.
[222] Docket No. 05-304, Order No. 6903 ¶¶297-298.
[223] Exh. 22: Tanos Rebuttal at 16:5-10.

it be adopted for use in this proceeding.

X. RATE DESIGN

A. The Company's CCOSS is not flawed and its Proposed Rate Design is Just and Reasonable

Staff's sole argument is that because, in their opinion, Delmarva's CCOSS is flawed, the rate design is also flawed and should be rejected.[224] The DPA argues that because the typical residential bill is already too high, with the increase proposed in this proceeding, Delmarva's rate design is unjust and unreasonable and, therefore, gradualism principles dictate the need to ease the effect of the increase.[225]

As already argued, Delmarva's CCOSS is not flawed, it is the same CCOSS that has been used in Docket Nos. 05-304, 09-414 and 11-528 that has formed the basis for rate design in those proceedings, and, therefore, the Company's CCOSS should be adopted. In preparing the Company's rate design, Company Witness Santacecilia testified that her job is to reflect as best as possible a fair and cost causative allocation of revenues.[226] She further confirmed that in using the Unitized Rate of Return (UROR), the Company attempts to put all of the rate classes on an equal footing.[227] The underlying assumption of the UROR is that every class reflects appropriately the costs it is putting on the system.[228] Therefore, there is no basis for DPA's argument that the rate design is unjust and unreasonable and violates the provisions of 26 *Del. C.* §303(a).

B. DEUG's Argument pertaining to the General Service Transmission Customers cannot be Supported

DEUG raises issues with the revenue allocation as it relates to the rate Delmarva

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[224] Staff brief at 94.
[225] DPA brief at 150; 154.
[226] Tr. at 882:2-4.
[227] Tr. at 883:1-3.
[228] Tr. at 883:10-12.

proposes to charge the General Service Transmission (GST) class. DEUG argues that Delmarva's proposal fails to properly account for the power factor credit provided to this class under certain circumstances which, they argue, reduces costs to and benefits the entire system. DEUG, therefore, proposes that the rate increase for GST class be no more than one-half the system average percentage increase.[229] The problem with this argument is two-fold. First, DEUG has not provided any evidence that there are reduced costs and benefits to the system resulting from the power factor credit, and second, Witness Phillips' proposal is arbitrary. Witness Santacecilia testified that she has no basis to know of the extent of benefits to other customers resulting from GST customers maintaining a 90% power factor because no study has been performed to make that determination.[230] And, DEUG Witness Phillips provided no evidentiary support for such contention; therefore, DEUG's position should be rejected.

The Company's rate design is consistent with the rate design used in prior dockets, is fair and reasonable and should be approved.

[229] DEUG brief at 3.
[230] Tr. at 895: 11-16.

CONCLUSION

Delmarva has requested in this proceeding a rate that will be reflective of the services provided by the Company during the rate effective period. The Company requests a rate base, cost of service and rate design that adheres to past ratemaking treatments approved by the Commission. On the [insert number] issues where Delmarva asks the Commission to recognize a treatment that differs from past Commission decisions, Delmarva identifies that it is seeking a change in precedent and provides the reasons why the change is appropriate. The record and Commission precedent, as summarized in the Company's Initial Brief and here, support the conclusion that the Company has met its burden in this proceeding. The Company has offered substantial evidence to support its cost of capital recommendation as well as the appropriate treatment of known and measurable post test period adjustments. Accordingly, Delmarva respectfully requests that its requested increase be approved.

Respectfully submitted,

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UNPUBLISHED OPINION. CHECK COURT RULES BEFORE CITING.

Superior Court of Delaware.
395 ASSOCIATES, LLC, Plaintiff/Appellant,
v.
NEW CASTLE COUNTY, et al., Defendants/Appellees.

No. 05A-01-013-JRJ.
Submitted Aug. 12, 2005.
Decided Nov. 28, 2005.

Richard L. Abbott, Hockessin, Delaware, for the Plaintiff/Appellant.

Mary A. Jacobson, New Castle, Delaware, for the Defendants/Appellees.

INTERIM ORDER

JURDEN, J.

*1 Having reviewed the written submissions, pertinent case law, Delaware Lawyers' Rules of Professional Conduct and Principles of Professionalism for Delaware Lawyers, the Court issues the following INTERIM ORDER. The Court raises Superior Court Civil Rule 12, subpart (f) *sua sponte* with regard to the content of Appellant's Reply Brief found on pages seven, two, three and four, respectively. The Court is aware this is an atypical application of Rule 12(f), in that case law suggests *sua sponte* rulings to strike are traditionally used to permit consideration of untimely motions to strike or motions to strike made under the incorrect rule.[FN1] However, the Court is obligated to undertake this inquiry, even absent a motion to strike by the Appellees, given the plainly disparaging and discourteous tone of the Appellant's briefing and the Court's interest in restoring professional civility in this matter. Thus, for the reasons that follow, the Court on its own initiative ORDERS STRICKEN from the Appellant's Reply Brief all of the improper commentary identified below. The Appellant is instructed to re-file an amended Reply Brief within ten (10) days of this INTERIM ORDER.

FN1. *See Myer v. Dyer,* 1987 WL 9669, at *2 (Del.Super.)(noting that "[e]ven if the motion is considered untimely, this Court may rule sua sponte to strike those portions of the Complaint ... it considers to be 'immaterial' or 'impertinent." '); *Stinnes Interoil, Inc. v. Petrokey Corp.,* 1983 WL 412258, at *1, (Del.Super.) (explaining that "since the Court, under this rule, may act on its own initiative, an untimely motion may be considered."); *Goldsmith v. Doctors for Emergency Services, Inc.,* 1984 WL 547849, at *1 (Del.Super.) (applying Super. Ct. Civ. R. 12(f) to a motion to strike brought under Rule 9(b), finding "[t]he Court, however, finding those portions [of the complaint] redundant ... will, of its own initiative, strike those portions.").

Procedural Background

By way of background, the Appellant filed its Complaint for a *writ of certiorari* on January 26, 2005, seeking appellate review of two administrative decisions: the July 13, 2004 Notice of Rule to Show Cause Decision issued by the New Castle County Department of Land Use and the December 30, 2004 Decision of the New Castle County Board of License, Inspection and Review (the "Board").[FN2] Specifically, the Appellant requests the reversal and remand of the Board's Decision, alleging that the Board: (1) proceeded irregularly by applying the incorrect legal standard and issuing an invalid written opinion; (2) committed errors of law in reaching it conclusions as to the issues of the statute of limitations, waiver, equitable estoppel and application of the BOCA

National Building Code; and (3) erroneously found the grading/drainage Violation Notice unsatisfied. The Court allowed the petition for the Appellant's *writ of certiorari* on February 7, 2005, and, on March 8, 2005, the record was filed with the Prothonotary. Pursuant to the June 16, 2005 modified briefing schedule, briefing in this matter concluded with Appellant's August 12, 2005 submission of the "Plaintiff's Reply Brief" that is presently at issue.[FN3]

FN2. Pl. Opening Br., *395 Assocs., LLC. v. New Castle County,* C.A. No. 05A-01-013 (Apr. 29, 2005). (D.I.8).

FN3. Pl. Reply Br., *395 Assocs., LLC. v. New Castle County,* C.A. No. 05A-01-013 (Aug. 12, 2005). (D.I.15).

Discussion

Motions to Strike are governed by Superior Court Civil Rule 12. Subpart (f) of Rule 12 permits the Court on its own initiative and at any time to "order stricken from any pleading ... any redundant, immaterial, [or] impertinent ... matter." As a general rule, party motions to strike such matters are disfavored.[FN4] Further, objectionable material will only be stricken if it is clearly found to be " 'unduly prejudicial.' "[FN5] Therefore, courts grant such motions "sparingly, and then only if clearly warranted, with doubt being resolved in favor of the pleading."[FN6]

FN4. *Messina v. Klugiewicz,* 2004 WL 1043793, at *2 n. 6 (Del. Ch.) (citing 2A J. MOORE, MOORE'S FEDERAL PRACTICE § 12.21[2], at 2317 (2d ed.1985)).

FN5. *Salem Church (Delaware) Assocs. v. New Castle County,* 2004 WL 1087341, at *3 (Del. Ch.) (considering a party's motion to strike under the equivalent Court of Chancery Rule, Ct. Ch. R. 12(f)); *Crowhorn v. Nationwide Mut. Ins. Co.,* 2001 WL 695542, at *7 (Del.Super.) (applying Super. Ct. Civ. R. 12(f)).

FN6. *Crowhorn,* 2001 WL 695542, at *7 (citing *Pack & Process, Inc. v. Celotex,* 503 A.2d 646, 660 (Del.Super.Ct.1985).

*2 To that end, the Court considers whether the matter pleaded "has some relevancy to the cause of action," "is directly in reply" to a matter pleaded and is "offered in support of a direct issue."[FN7] Accordingly, an "immaterial" matter is defined as one that has "no essential or important relationship to the claim for relief or the defenses being pleaded, or a statement of unnecessary particulars in connection with and descriptive of that which is material."[FN8] Similarly, statements that "do not pertain, and are not necessary, to the issues in question" are "impertinent" materials.[FN9] A matter can be stricken if it clearly has "no possible bearing on the subject matter of the litigation" or fails to "set out any issuable fact" and is found "unduly prejudicial" to a party.[FN10]

FN7. *Id.* (citing *Pack & Process,* 503 A.2d at 660).

FN8. *Salem,* 2004 WL 1087341, at *2 (citing 5A CHARLES ALAN WRIGHT & ARTHUR R. MILLER, FEDERAL PRACTICE AND PROCEDURE § 1382, at 706-08 (2d ed.1990)).

FN9. *Salem,* at *2 (citing 5A CHARLES ALAN WRIGHT & ARTHUR R. MILLER, FEDERAL PRACTICE AND PROCEDURE § 1382, at 711 (2d ed.1990)).

FN10. *Messina,* 2004 WL 1043793, at *2 n. 6; *Crowhorn,* 2001 WL 695542, at *7 (citing *Pack & Process,* 503 A.2d at 660); *Salem,* 2004 WL 1087341, at *3.

With regard to the Appellant's Reply Brief, the Court questions what possible connection or relationship exists between the Appellant's allegations that the Board proceeded irregularly under an incorrect legal standard or that its written conclusions were fabricated by its attorney, and the abusive commentary on page seven of the Appellant's Reply Brief.[FN11] Page seven contains a diatribe opining that citizens' boards ignore applicable legal standards in decision making and are the functional equivalent of an appointed "group of monkeys." [FN12] This disparagement culminates with the Appellant's assertion that such a board permits its attorney to "interpret the grunts and groans of the ape members" to reach "whatever conclusions" the attorney wishes based on the record.[FN13] These statements are disgraceful and have no place in our Bar or this Court. The statements serve no other purpose than to inflame, insult and offend, and have no legal "value or relevancy" to the relief sought by the Appellant or defenses offered by the Appellees on appeal.[FN14]

FN11. *Crowhorn,* 2001 WL 695542, at *8.

FN12. Pl. Reply Br., at 7. (D.I.15).

FN13. *Id.*

FN14. *Crowhorn,* 2001 WL 695542, at *8.

Unfortunately, the Appellant does not stop there. Instead the Appellant peppers its legal arguments with uncivil and unnecessarily rude critiques of the Appellees' positions that drip with sarcasm.[FN15] The two most egregious of these attacks appear in the closing paragraph of the Appellant's "Counter-Statement of Facts" and the opening paragraph of its argument. [FN16] The Appellant closes its recitation of the facts by asking the sardonic and unnecessary question: "Why would the [Appellee] want to start making decisions on the merits when it could continue to run [the Appellant] into the ground for sport based upon whatever whimsical speculation the [Appellee] could conjure up?" [FN17]

FN15. Pl. Reply Br., at 1 n. 1 ("snide litigation tactic"), 2 ("Laughably, the County found ..."), 3 ("To describe such irresponsible ... conduct as arbitrary would be charitable."), 18 ("The County is so confused ...").

FN16. *See* Pl. Reply Br.. at 2-3, 4.

FN17. *Id.* at 2-3.

The Appellant's argument section follows with, "[n]ever one to miss an opportunity to deny a party the right to a fair and impartial hearing on the merits, the County outdoes itself again by raising for the first time on appeal that [the Appellant] is barred from appealing the timely filed Rule to Show Cause decision ..." [FN18] This attack, impugning the honesty, fairness, integrity, impartiality, and competence of the Appellee is highly inappropriate and constitutes "undignified or discourteous conduct that is degrading to a tribunal." The Appellant concludes this paragraph by directing the Court's attention to Appellees' legal authority cited in their Answer because it will "quickly dispense with this ridiculous argument." [FN19] Like the undignified and discourteous "monkey" analogies discussed above, the Court finds this content to be "impertinent material" that does not pertain and is wholly unnecessary to the issues at bar.[FN20] It has "no essential or important relationship" to any claims made in the Appellant's writ or Appellees' defenses.[FN21]

FN18. Pl. Reply Br., at 4.

FN19. *Id.*

FN20. *Board of Education v. Sussex Tech Education Ass'n.,* 1998 WL 157373, at *2 (Del. Ch.) (granting a motion to strike portions of a complaint, detailing a party's improper touching of a student, as "irrelevant and prejudicial allegations" included for "no legally appropriate reason" given the "purely procedural issue" of which tribunal "should decide the question of arbitrability.").

FN21. *Salem,* 2004 WL 1087341, at *2.

*3 Not only are the above statements irrelevant to resolution of the issues on appeal, but this unprofessional discourse is prejudicial because it places before the Court inflammatory statements implicating the integrity, intellect and competence of the Appellees and their attorney in an ill fated attempt to color the Court's perception of the legal issues before it. Consequently, the Appellant is ordered to strike all of these statements from its Reply Brief and re-file its amended reply in ten (10) days.

Finally, the Court expresses its deep concern about the unnecessarily antagonistic tenor of written advocacy in this case. The Court agrees that the Appellees' reference to the Appellant's principal forming his own home warranty company "[r]ather than purchase a home warranty from a reputable and established ... company" was at best unnecessary.[FN22] However, it in no way justifies the Appellant's subsequent uncivil commentary offered to the Court in its briefing. Nor does it justify raising the issue informally, via footnote in the Appellant's "Counter-Statement of Facts," that suggests the comment represents the Appellees' hope that "the Court will decide the matter based upon any potential bias or prejudice that it may have against [the principal], rather than on the merits."[FN23]

FN22. Def. Answering Br., *395 Assocs. LLC v. New Castle County,* C.A. No. 05A-01-013 (Jul. 22, 2005), at 3. (D.I.14).

FN23. Pl. Reply Br., at 1 n. 1. (D.I.15).

It is troubling that the Court must remind counsel for both parties that incivility and personal attacks cross the boundary of zealous advocacy into the realm of unprofessional conduct that only degrades the quality the legal practice in Delaware. Counsel should remember that "[t]he ethical standard requiring lawyers to represent a client zealously is qualified by the phrase 'within the bounds of the law." '[FN24] "[T]heir role is to zealously advance the legitimate interests of their clients, while maintaining appropriate standards of civility and decorum."[FN25] "Civility is an attitude, a way of thinking that demands people be treated with dignity and respect."[FN26] As explained by the Delaware Supreme Court, civility plays:

FN24. Randy J. Holland, *President's Message,* THE BENCHER, Jul./ Aug.2003, at 2.

FN25. CODE OF PRETRIAL CONDUCT 4(a) (Am. Coll. of Trial Lawyers 2002).

FN26. Jason Hawkins, *Language & Civility,* THE BENCHER, Jul./Aug.2005, at 13.

an important role in the administration of civil and criminal justice. Without it, litigation becomes even more expensive and public trust and confidence in the administration of justice is undermined.[FN27]

FN27. *Kaung v. Cole Nat. Corp.,* 884 A.2d 500, 507 (Del.2005).

Moreover, counsel should bear in mind that legal professionals who bring:

"a clear commitment to thoughtful listening, tolerant mutual respect, and measured, caring advocacy and decision making":[FN28] shine a light upon the meaning of ordered liberty for all who are affected by the justice system. We are the keepers of civility in that system. We are the keepers of the rule of law. We must, therefore, be models of civility wherever we are.[FN29]

FN28. Deanell R. Tacha, *President's Message,* THE BENCHER, Jul./ Aug.2005, at 2.

FN29. *Id.*

Within the practice of law, courtesy, formality and decorum are not simply a matter of form:

[d]ecorum makes for efficiency in the courtroom and an increase in the exchange of information. Rule of decorum and etiquette prevent chaos ... and assist in the discovery of truth between conflicting evidence. Disruptive tactics thwart justice. Civility aids ethics while incivility corrupts. FN30

FN30. John J. Jurcyk, Jr., *Honor The Law! The Essential Role of Civility in the Legal System,* THE BENCHER, Jul./Aug.2005, at 21.

*4 Specifically, with regard to the benefits of professional, civil conduct before judges, one commentator has noted that:

[a] courteous presentation permits the decision maker to concentrate on the subject matter at hand rather than have to rule out distractions caused by rudeness, inappropriate behavior or personal attacks. FN31

FN31. *Id.* at 20.

Thus, for the benefit of all parties and in the interests of the administration of justice, this Court reminds counsel that it expects *"all* counsel will act to represent their respective clients in an exemplary manner with conscious respect of the fine professional traditions that Delaware attorneys are expected to present in our courts." FN32 "Counsel are all professionals and, as Delaware attorneys, should take justifiable pride in attorney civility which has been promoted within this State." FN33 Therefore, they "should not reflect any ill feelings that clients may have toward their adversaries," in their dealings with the Court and other counsel. FN34 Counsel are also reminded that:

FN32. *Crowhorn v. Nationwide Mut. Ins. Co.,* 2002 WL 1274052, at *5 (Del.Super.)

FN33. *State v. Aizupitis,* 1996 WL 33322267, at *3 (Del.Super.).

FN34. CODE OF PRETRIAL CONDUCT 4(a) (Am. Coll. of Trial Lawyers 2002).

lawyers are always engaged in the administration of justice.... The public's respect for the administration of justice is frequently a function of how they see lawyers-the officers of the court-conduct themselves in routine matters. FN35

FN35. Randy J. Holland, *President's Message,* THE BENCHER, Jul./ Aug.2003, at 2.

Generally, [l]awyers should treat all other lawyers, all parties, and all witnesses courteously, not only in court, but also in other written ... communications." FN36 Written submissions to the court "should [not] disparage the integrity, intelligence, morals, ethics, or personal behavior of an adversary unless such matters are directly relevant under the controlling substantive law." FN37 Further, counsel "should avoid hostile, demeaning, or humiliating words in written and oral communication with adversaries." FN38

FN36. CODE OF PRETRIAL CONDUCT 4(a).

FN37. CODE OF PRETRIAL CONDUCT 3.

FN38. CODE OF PRETRIAL CONDUCT 4(b).

As the Court made clear in *Crowhorn v. Nationwide Mutual Insurance Company,* this Court will not "[condone] or ... accept or permit the use of profanity, acrimony, derisive gibes, or sarcasm with respect to any communication related to any matter, proceeding, writing, meeting, etc." involved in pending cases. FN39 And, although a member of the Delaware Bar submitted the uncivil briefing presently before this Court, and not an attorney admitted *pro hac vice,* the Court's recommendation in *Crowhorn* is still appropriate: "both parties ... should become intimately familiar with the preferred conduct for Delaware attorneys as set forth in Delaware Supreme Court Rule 71 which contains the Delaware State Bar Association Statement of Principles of Lawyer Conduct." FN40 Specifically, the Court directs counsel's attention to the Principles of Professionalism for Delaware Lawyers, subpart A (1)-(4), which provides in pertinent part, that Delaware attorneys should:

> FN39. *Crowhorn,* 2002 WL 1274052, at *5 (finding revocation of the admission *pro hac vice* of an attorney unnecessary to preserve the integrity or fairness of proceedings in spite of behavior that included the use of similar uncivil language in correspondence during an earlier arbitration.).

> FN40. *Id.*

develop and maintain the qualities of integrity ... [and] civility ... that mark the most admired members of our profession ... A lawyer's integrity requires personal conduct that does not impair the rendering of professional service of the highest skill and ability; ... [and] treating others with respect ... [A] lawyer ... should treat all persons, including adverse lawyers and parties, fairly and equitably.... Professional civility is conduct that shows respect ... for the courts and colleagues.... Respect for the court requires ... emotional self-control; ... the absence of scorn and superiority in words of demeanor.... A lawyer should represent a client with vigor.... Such representation, however, does not justify conduct that ... is abusive, rude or disrespectful. A lawyer should recognize that such conduct may be detrimental to a client's interests and contrary to the administration of justice. FN41

> FN41. Supr. Ct. R. 71(b)(ii)

*5 As its final point, the Court instructs Appellant's counsel that:

[t]he profession [will] go a long way toward reaching a reputation of professionalism and civility if we do our best to think first and act as we would want to be treated.... The purpose of this profession is to serve clients, the public and the administration of justice. Therefore, as officers of the Court, we are duty bound to be professional and civil. FN42

> FN42. John J. Jurcyk, Jr., *Honor The Law! The Essential Role of Civility in the Legal System,* THE BENCHER, Jul./Aug.2005, at 21.

It is a sad day when the Court must intervene in matters of this sort, which may implicate Rule 3.5.(d) of the Delaware Lawyers' Rules of Professional Conduct. FN43 Having now done so, the Court does not anticipate any further incivility, unprofessional written advocacy or other undignified or discourteous conduct that is degrading to the Court and casts a pall over our rich tradition of civility and professionalism.

> FN43. DEL. LAWYERS' RULES OF PROF'L CONDUCT R. 3.5(d): "A lawyer shall not ... engage in conduct intended to disrupt a tribunal or engage in undignified or discourteous conduct that is degrading to a tribunal." *See also Matter of Shearin,* 721 A.2d 157, 162 (Del.1998); *Matter of Ramunno,* 625 A.2d 248 (Del.1993); *Paramount Commc'ns v. QVC Network,* 637 A.2d 34, 53 (Del.1993).

IT IS SO ORDERED.

Del.Super.,2005.
395 Associates, LLC v. New Castle County
Not Reported in A.2d, 2005 WL 3194566 (Del.Super.)

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UNPUBLISHED OPINION. CHECK COURT RULES BEFORE CITING.

Superior Court of Delaware, New Castle County.

CAROUSEL STUDIO, Appellant,
v.
UNEMPLOYMENT INSURANCE APPEAL BOARD, Appellee.

C.A. No. 89A-AU-7. | Submitted: Nov. 8, 1989. | Decided: June 26, 1990.

Attorneys and Law Firms

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Suzanne Quinn, appellee, pro se.

Opinion

MEMORANDUM OPINION

BABIARZ, Judge.

*1 The Unemployment Insurance Appeal Board conducted a hearing concerning Suzanne Quinn's appeal of the decision of the Appeals Referee that she left her employment without just cause and was thus disqualified for benefits under 10 *Del.C.* § 3315(1). After hearing additional testimony offered by both parties, the Board reversed the decision of the Referee and held that Quinn had been discharged without cause and thus was eligible for benefits under 10 *Del.C.* § 3315(2). Currently before the Court is Carousel's appeal from the Board's decision.

Carousel contends that it was denied procedural due process in that the Board, without adequate notice, conducted a *de novo* review exceeding its authority and that Quinn was allowed to relitigate the issues before the Board, whereas Carousel's representative was not accorded a reasonable opportunity to reply or similarly relitigate the issues before the Board closed the record. Furthermore, Carousel contends that it was denied substantive due process in that Quinn produced no new credible and probative information sufficient to support the reversal of the Appeals Referee's decision.

No particular form of proceeding is required to constitute procedural due process in administrative proceedings; all that is required is that the liberty and property interests of the parties be protected by the rudimentary requirements of fair play. *Mitchell v. Delaware Alcoholic Beverage Commission,* Del.Super., 193 A.2d 294, 311-312 (1963) rev'd on other grounds, Del.Supr., 196 A.2d 410 (1963). 19 *Del.C.* § 3321(a) provides that the Board may prescribe the manner in which hearings before the Board are conducted.

The Notice of Hearing before the Board sent to Carousel summarized the procedures as set forth in the *Unemployment Insurance Handbook for Employers (1989):*

An appeal has been filed against an Appeal Referee's decision concerning a claim for unemployment benefits. A hearing has been scheduled before the [UIAB]. This hearing is not a *de novo* review and the parties will not be permitted to relitigate the case in its entirety. Each party will be given the opportunity to present additional relevant evidence and legal argument as to why the Referee's decision should be upheld or reversed.

If witnesses are needed to help you present your case you must arrange for their appearance at the hearing.

In the exercise of quasi-judicial or adjudicatory administrative power, administrative hearings like judicial proceedings are governed by the fundamental requirements of fairness which are the essence of due process, including fair notice of the scope of the proceedings and adherence of the agency to the stated scope of those proceedings. See *General Chemical Division, Allied Chemical and Dye Corp., v. Fasano,* 94 A.2d 600 (1953); *Shields v. Utah Idaho Central Railroad Company,* 305 U.S. 177, 59 S.Ct. 160, 83 L.Ed. 111 (1938); *Morgan v. United States,* 304 U.S. 1, 58 S.Ct. 733, 82 L.Ed. 1129 (1937).

Due process as it relates to the requisite characteristics of the proceedings entails providing the parties to the proceeding with the opportunity to be heard, by presenting testimony or otherwise, and the right of controverting, by proof, every material fact which bears on the question of right in the matter involved in an orderly proceeding appropriate to the nature of the hearing and adapted to meet its ends. See generally 2 *Am.Jur.Administrative Law* § 353, p. 166.

*2 After reviewing the transcript of the hearings before the Referee and the Board, I am satisfied that a fair and impartial hearing was conducted before the Board. At the beginning of the hearing the Board advised the parties to keep in mind that the proceeding before the Referee was a part of its record and that they wanted to hear "any new evidence or testimony or dispute of any findings of fact of the Referee. Both parties were unrepresented by counsel, therefore the Board acted properly in permitting the parties latitude in presenting their cases. It should not be expected that the issues would be addressed with the directness and skill of an attorney trained in the art of advocacy. Each party was afforded an equal opportunity to present its case, and, under the circumstances, the Board restricted the scope of the hearing as much as possible to only relevant issues bearing upon the Referee's decision.

The Notice of Hearing advised Carousel that additional relevant testimony would be permitted by the parties. At the close of the designated time for the hearing, one of the Board members expressed that after hearing the testimony he still did not understand why Judith Donahue, the owner of Carousel, alleges that Quinn abandoned her job. Donahue was afforded an opportunity to readdress specific issues that were unclear to the members of the Board and likewise Quinn was afforded a rebuttal. During the hearing Donahue raised no objections to any of the testimony offered by Quinn and was offered ample opportunity to offer testimony addressing Quinn's allegations. Furthermore, Donahue raised no objection to the close of the proceedings which had already been extended to permit her an additional opportunity to clarify or add to her prior testimony. I am satisfied that both parties presented their case to the Board and Carousel was, therefore, afforded procedural due process.

Carousel next contends that the Board disregarded the record before the Referee and conducted a *de novo* review of the case. The record, however, does not support this contention. At the onset of the hearing the Board announced that the record before the Referee was a part of its record and the Referee's findings were incorporated by reference in the summary of evidence portion of its written decision.

Although the Board never addressed the Referee's findings specifically or indicated reasons why those findings were unacceptable, there is no requirement that the Referee's decision be specifically addressed. Rather, the Board's obligation, when it assumes that the evidence submitted to the Referee is part of the record, is that it must review the record of the Referee before it decides the case or due process may be violated. See *Kowalski v. Unemployment Insurance Appeal Board,* Del.Super., C.A. No. 88A-JL-3, Gebelein, J. (Jan. 22, 1990). Carousel has not provided the Court with anything more than a naked allegation that the Board disregarded the record generated before the Referee. Neither the Board's conduct at the hearing nor the content of its written opinion indicate that the Board disregarded the record before the Referee. I am satisfied that the Board did not exceed its powers of review and considered all the evidence submitted in both hearings.

*3 Carousel contends that Quinn presented the Board with no new credible and probative information sufficient to support the reversal of the Appeals Referee's decision.

This Court's appellate jurisdiction over the decisions of the Board is very limited. The factual determinations of the Board, if supported by substantial evidence, and in the absence of fraud, shall be conclusive and the jurisdiction of this Court shall be confined to questions of law. See 19 *Del.C.* § 3323(a); see also *Delgado v. Unemployment Insurance Appeal Board,* Del.Super., 295 A.2d 585 (1972); *Boughton v. Division of Unemployment Insurance of Department of Labor,* Del.Super., 300 A.2d 25 (1972); *Ortiz v. Unemployment Insurance Appeal Board,* Del.Super., 305 A.2d 629 (1973), rev'd on other grounds, Del.Supr., 317 A.2d 100 (1974).

The dispute between Quinn and her employer resulting in this action concerns whether Quinn was fired or quit. At the Referee's hearing, Quinn and Donahue were the only witnesses who testified. The testimony offered by the two regarding the events which led to the termination of Quinn's employment was relatively consistent, however, each interpreted the significance of their actions and their intentions differently. Because neither Quinn stated to Donahue that she was quitting her job nor did Donahue state to Quinn that she was fired, the Referee was required to make decisions concerning the intentions of the parties based upon their testimony, ultimately involving determinations of credibility. Quinn contested many of the factual determinations of the Referee and appealed his decision to the Board on that basis.

In *Renshaw v. Widener University and Unemployment Insurance Appeal Board,* Del.Super., C.A. No. 84A-NO-16, Babiarz, J. (Jan. 2, 1987), like the case at hand, determinations of intent had to be made requiring the Referee to weigh the credibility of the parties' testimony. The decision of the Referee was appealed to the Board and reversed without a hearing. The Court stated that under ordinary standards of review, in the absence of a supplementary or *de novo* hearing, the Board would be obliged to accept the factual determination of the Referee, if supported by substantial evidence. *Id* at 2.

Although in *Renshaw* the Court interpreted 19 *Del.C.* § 3320 as granting the Board *carte blanche* in reviewing the factual findings of a Referee, it stated its reluctance to affirm a decision of the Board which amounted to a naked judgment of credibility different from that arrived at by the officer who heard the testimony. The Court, nonetheless, affirmed the Board's decision because it was based upon a logical and reasoned analysis of the evidence presented at the hearing before the Referee and did not offend the general principle that great deference is owed to the factual findings of a trial officer. *Id* at 2 (citing *Levin v. Smith,* Del.Supr., 513 A.2d 1292 (1986).

Thus, the standard in Delaware is that the Board need not accept the findings of the Referee if its decision is a logical and reasoned analysis of the entire record and supported by substantial evidence. See *Kowalski,* supra at 22-25. In the instant case, not only did the Board have the record before the Referee, it was able to independently observe the demeanor of Quinn and Donahue and weigh their credibility. The Board also heard the testimony of Cyndi Kowalczyk from the Department of Labor, an impartial witness whose testimony supported Quinn's case.

***4** It is not the Court's province to reevaluate evidence presented to the Board and make its own decisions as to the credibility of the witnesses, the weight of their testimony, or the reasonable inferences that may be drawn therefrom. *Coleman v. Department of Labor,* 288 A.2d 285 (1972). Therefore, if there is such relevant and competent evidence as a reasonable mind might accept as adequate to support the conclusions of the Board, the Court will not disturb its findings. See *Quaker Hill Place v. State Human Rights Commission,* Del.Super., 498 A.2d 175, 179 (1985).

The findings of the Board serving as the factual predicate to its determination that Ms. Quinn was fired and had not quit are supported by the evidence. The evidence is quite clear that both Quinn and Donahue were dissatisfied and tension between the two was increasing. In the morning of the final day of Quinn's employment an argument ensued at which time both parties expressed their dissatisfaction with the employment arrangement. After finding that Quinn had not expressed an intention to quit her job but that a leave of absence had been discussed, the Board focused its attention on the haste with which Donahue acted in contacting the Chamber of Commerce and the Department of Rehabilitation to notify them that Quinn had quit her job. A reasonable inference can be drawn that, in light of the increasing tension between the two and the arguments that ensued, Donahue, frustrated with the entire situation and possibly angered by Quinn's comment that Donahue was the worst person she ever worked for, hastily and impulsively acted in a manner which would lead one to conclude that she had discharged Quinn.

Although the evidence could arguably support a contrary conclusion that Quinn quit, the Court must give deference to the Board's findings. The Board had before it the record before the Referee and had the opportunity to observe the demeanor of the witnesses firsthand and make its own assessment of the credibility of the witnesses and draw its own conclusions and inferences from the witnesses' testimony. I find that there is such relevant and competent evidence as a reasonable mind might accept as adequate to support the conclusions of the Board; therefore the decision of the Board is affirmed.

IT IS SO ORDERED.

End of Document

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF DELAWARE
VOLUME 1

IN RE: IN THE MATTER OF :
THE INVESTIGATION INTO :
DELMARVA POWER & LIGHT :
COMPANY'S RATE REQUEST FOR : PSC DOCKET NO. 13-152
DISTRIBUTION INFRASTRUCTURE:
INVESTMENT (FILED APRIL 16,:
2013) :

Public Service Commission Hearing taken pursuant to notice before Gloria M. D'Amore, Registered Professional Reporter, in the offices of the Public Service Commission, 861 Silver Lake Boulevard, Cannon Building, Suite 100, Dover, Delaware, on Tuesday, April 23, 2013 beginning at approximately 1:31 p.m., there being present:

APPEARANCES:

On behalf of the Public Service Commission:
J. DALLAS WINSLOW, CHAIR
JAY LESTER, COMMISSIONER
JOANN CONAWAY, COMMISSIONER

VERITEXT NATIONAL COURT REPORTING COMPANY
MID-ATLANTIC REGION
300 Delaware Avenue Suite 815
Wilmington, DE 19801
(302) 571-0510

APPEARANCES CONTINUED:

On behalf of the Public Service Commission Staff:
JULIE DONOGHUE, ESQUIRE

On behalf of the Public Service Commission Staff:
JAMES McC. GEDDES, ESQUIRE

On behalf of the Public Service Commission Staff:
LAWRENCE W. LEWIS, ESQUIRE

On behalf of the Public Service Commission Staff:
ROBERT HOWATT, EXECUTIVE DIRECTOR
JANIS L. DILLARD, DEPUTY DIRECTOR
ALISA BENTLEY, SECRETARY
OCTAVIA WOODARD, SECRETARY

On behalf of the Attorney General's Office:
REGINA IORII, ESQUIRE
JAMES ADAMS, STATE SOLICITOR

On behalf of Delmarva Power & Light Company:
TODD GOODMAN, ESQUIRE

CHAIR WINSLOW: Next on the agenda is Item No. 5, in the matter of the investigation into Delmarva Power and Light Company's rate request for distribution infrastructure investment to consider Staff's motion of proposed Order 8363 seeking relief on behalf of Delmarva Power & Light's customers regarding excessive investment distribution and reliability infrastructure.

Mr. Geddes.

MR. GEDDES: Chair Winslow, Members of the Commission. It's nice to be back.

CHAIR WINSLOW: Nice to see you. It's additive to see you.

MR. GEDDES: I have great help here next to me. So, hopefully, I won't stumble along too badly this afternoon.

This is Staff's motion that was filed last week, which asked the Commission to consider whether a separate docket should be opened to consider the level of investment in Delmarva's electric distribution system.

The motion is pretty straightforward, and the reasons for it are set forth in the motion. And I would also suggest to you that the response that the company filed yesterday, unfortunately, is predictable in supervise and regulate. It is great policy for the company, and then, basically, the company is supposed to meet those standards, those regulations, those requirements.

And Reg 50 is a perfect example. Those standards were set for reliability and the company has an obligation to meet them.

So, to suggest somehow that we are trying to tinker around with the day-to-day management of the company, I believe it is a little disingenuous.

But the reason why this will not work in this rate case is because first, as you know, rate cases are on a seven-month trigger. And rate cases are pretty much accounting cases, green eye shape, how much investment, what's the return, what kind of revenues do we have and what's the deficiencies that the company should be entitled to collect.

Occasionally we get into some rate design issues, but recently those have been somewhat few and far between, although I would say AMI was an issue that we spent some time on in the last case.

But pretty much it's accounting. It's not policy. It's not determining whether there should be additional standards or additional metrics to review these investments.

Now, why is Staff concerned about this all of a sudden. Well, if you look at the company's filing, and some of those facts are in the motion, we have a $300 million dollar investment coming down the line captioned as reliability.

Now, I've spent a few years in this chair, and I know that in the '80's and in the '90's and in the beginning of the 2000's, which I think they called the odds, but in any event, I never heard of reliability investment. It was just investment.

And now, in the company's case, we have 80 percent of their projected construction over the next five years captioned as reliability investments. $300 million dollars. Not something to sneeze at.

And what do we have in the current case. We have $10 million dollars of reliability additions in the current case.

Now, I'm not asking you to, obviously, get involved in the facts of the current case, but this is part of their filing, which clearly indicates that the case is made up of an attempt to capture $10 million dollars in reliability investment. That still leaves almost $300 million dollars not in the case. And query, where are we going to have an opportunity to look at that? Are we supposed to look at it on a case-by-case basis, or would it be better if we looked at it in the context of creating some standards or some guidance for customers as to why this additional investment is necessary?

So, it's clear that this can't be done in this particular case as the company suggest. And we're not asking for public comment. We're asking for public forums. There's a difference.

The comment is just where the public come in and puts their comments on the record. We're asking specifically that public forums be set up where senior management comes and the public can come and the public can get guidance on the need for these investments, why they have to be done now, and most interesting, what kind of cost containment, what kind of programs is the company engaged in in trying to reduce these costs, what impact does it have on O&M. I mean, presumably, if we are putting all of this money into the ground, there should be some return on reduced operation and maintenance cost.

All of that needs to be looked at in the context of $300 million dollars of reliability investment, not the $10 million that sits in this current case that the company is involved in.

So, that's the reason why on a procedural basis, we think it is important so that we can look at it globally and not just look at it individually.

Now, the third argument they make, there are some days when you just love practicing law. And being an administrative lawyer and having the opportunity to share time with the three of you, sometimes four, sometimes five. But Mr. Goodman, I love Mr. Goodman, he's a great guy, but he takes us to task for allegedly not being clear to the Commission about the company's efforts with regard to creating metrics for reliability investment.

And if you look at his footnote on Page 7, I just have to read it, it is so grand, Delmarva's Counsel regrets having to attach informal E-mail communications between Counsel to this response. It is however, Staff that has made the flawed representation that Delmarva has not moved forward with its settlement obligation on reliability issues. Duty bound to both the client and the Commission to make sure. And then he has some other comments, as I recall, fulmination about this alleged attempt by Staff to not be clear.

Now, the company attaches as Exhibit No. 1 an E-mail, and I agree with them. I do not believe the E-mails should be attached to the motion. But he opened the door. So, we'll just proceed ahead.

So, he has this E-mail, which is addressed to Janis and myself, saying, you know, what are doing about metrics. And I will tell you that when we cancelled the hearings in the prior case in 11-528 in August of last year, this was an issue. And I know it because it was the issue I was most concerned about. And we made sure that it was in the settlement agreement that came before the Commission that you approved in December that there was language in there that we would talk about multiyear rate cases and we would talk about these other matters.

So, in response to this motion, Mr. Goodman says, Well, here is my letter. It says, you know, Oh, I reached out to you. And the last part of that letter says, Let us know your thoughts. Well, you know, I did let Mr. Goodman know my thoughts. And, in fact, I wrote to him on February 27th and said, Yes, we're having a meeting March 14th. Why don't you develop some metrics, and we'll talk about them. And we met on the 14th about multiyear, and we met on April 11th about multiyear.

Well, I'm just going off your motion, Todd. There are lots of correspondence running around.

But in any event, I asked the company whether they would develop some metrics. I copied Janis. I copied Amy. I copied the people who were working on this.

And so, I find it somewhat curious after 31 pages of multiyear material, the last page is the best. Begin the deeper dive. I thought I was going to be certified for SCUBA diving registration.

In any event, we have 31 pages of multiyear Powerpoint presentations, analysis. But on the metric side, we don't have anything. We have zero. Notta. Nothing.

Now, I'm not saying that the company isn't willing to do that. I was only making the position of Staff in our motion to say it has been eight months and he don't have any metrics. We now know that we have 300 -- let me try this again -- $397 million dollars worth of investment coming of which $309 million is reliability. We need to understand how we are going to convince ratepayers that the improved service that the company continues to talk about is measurable and quantifiable.

If you saw the letter to the editor yesterday by Mr. "Petrocelli," he was suggesting in his comments about the excessive compensation to the executives that he didn't see, in his world, any improvement in service and was wondering why he should pay more in rates.

So, the Commission clearly has the right and the opportunity to set up a separate docket, if it feels, in its administration of the supervision and regulations of this company, to investigate whether this amount of investment is appropriate and whether additional standards to measure it should be implemented.

This is not accounting. This is something that's a lot bigger, and it's going to require a lot of effort. It cannot be done in a single case. And it clearly stretches out until 2017.

So, for those reasons, that's why Staff believes this is appropriate. And I do find it curious that the company, again, won't take this opportunity and say, yes, okay, we understand these things, and maybe it would be helpful to everybody to have a focused proceeding on these numbers and some metrics. And it would help them ultimately, I think.

us to do, and now this comes. So, none of this is making sense.

CHAIR WINSLOW: To you?

MR. GOODMAN: Right.

CHAIR WINSLOW: Mr. Goodman, with respect to the argument made by Mr. Geddes that there are issues in this particular request by Staff that are beyond the scope of the rate base case, I didn't really hear you make any substantive argument against that argument.

Is there something that you forgot to say, or is there something you would like to say?

MR. GOODMAN: Let me try to do a better job.

The settlement itself, which is now an order approved by you, you will accept the settlement of the case under the terms set forth in the settlement is for Staff, the Public Advocate, to work together outside of the confines of the case to do certain things.

Two of those, the two main things are work on this reliability concern. How can we show customers that they get a benefit in some quantifiable way from this reliability spent. You ordered us to do that.

We have had people working on it since the day, actually before you, way before you approved the settlement, and that's what we are doing. So, this absolutely came out of the blue. And it is cutting it off. I don't think it is appropriate. That's the substantive thing. It's stopping us from doing us what we've been ordered to do.

CHAIR WINSLOW: My perception of the situation is, there has been a settlement. There has been some discussion. But the Staff wants to know about the future. There are a lot of the discussions, obviously, some of the discussions are about the future. But that is what they are really looking at.

MR. GOODMAN: Absolutely.

CHAIR WINSLOW: And it appears to me from my hearing of the discussion that Ms. Iorii agrees with Mr. Geddes that there will be items outside of the relevant inquiry at the rate base case that they would, or that you could successfully object to if it were in the rate base case, not that you would necessarily for some certain reasons. There seems to be a different element here. And I haven't really heard anything that indicates to the opposite.

MR. GOODMAN: You're correct. There is

Proposed Forward Looking Rate Plan of

Delmarva Power & Light Company

Docket No. __________

Cover Letter
Direct Testimony and Schedules of
Moore, Zibinski, and Santacecilia

Before the Delaware Public Service Commission

October 2, 2013

delmarva power
A PHI Company

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Gary R. Stockbridge
President, Delmarva Power Region

Todd L. Goodman
Associate General Counsel

October 2, 2013

Alisa C. Bentley, Secretary
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Cannon Building
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Bob Howatt, Executive Director
Delaware Public Service Commission
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Re: Policy Filing - Delmarva Power & Light Company's Proposed Forward Looking Rate Plan

Dear Secretary Bentley and Mr. Howatt:

Enclosed for filing with the Commission is Delmarva Power & Light Company's (Delmarva or the Company) policy filing entitled: "Proposed Forward Looking Rate Plan of Delmarva Power & Light Company." The proposed Forward Looking Rate Plan (or "FLRP") arises out of the obligation of the parties as set forth in the Settlement of Delmarva's last electric base rate case (Docket No. 11-528), which was approved by the Commission in Order No. 8265 (the "11-528 Settlement"). The pertinent portion of the 11-528 Settlement provides that Delmarva, Commission Staff ("Staff") and the Division of the Public Advocate ("Public Advocate") agree "to meet and discuss several issues outside the confines of [a] rate proceeding in the hopes of resolving each of them." Those issues include:

1) the establishment of metrics to help customers understand how investment in Delmarva's plant in service benefits them in a quantifiable manner, and

2) alternative regulatory methodologies which would include, but not be limited to, multi-year rate plans.

Immediately following the 11-528 Settlement, Delmarva began working in earnest on the development of an alternative regulatory methodology that would accomplish both of the issues addressed above. Delmarva, Staff, and the Public Advocate began meeting informally and discussing the general design concepts of a plan. These discussions spanned several months and included a number of potential components of the Forward Looking Rate Plan, including but not limited to: customer and Company impacts, potential terms and conditions, levels of spending for capital and operations and maintenance (or O&M) costs, and the development of more stringent minimum reliability performance standards. While the FLRP is a Delmarva proposal, it incorporates issues of importance to Staff and the Public Advocate, many of which were developed during these meetings.

The FLRP presents a change from the traditional rate making process used for many years. Unlike the traditional rate making process, where the Commission looks at a past "test year" in an effort to set rates that will reflect a utility's cost during a future rate effective period, the FLRP aligns rates with the costs actually being incurred to provide service. This alignment is achieved by estimating the amount that Delmarva will spend on capital and O&M for each of the future four years that FLRP rates will be in effect. Rates are established based upon the amount of spending determined to be appropriate for those four future years. As explained below, this change will provide significant benefits to customers, the Company, and the State. A number of events have led Delmarva to the conclusion that now is the time to consider the benefits of a multi-year or "forward looking" rate plan, including:

- Customer research has established that the primary issue of importance to Delmarva's customers, both business and residential, is the reliability of electric service;

- The increased frequency and severity of storms over the last decade, coupled with the damage to the regional grid and economic impact caused by these storms, has resulted in a national recognition of the critical need to make the system less vulnerable to weather-related outages and reduce the time it takes to restore power after an outage occurs.

- The digital/electronic requirements of individuals, business, government, communication systems, healthcare and emergency services have developed to the point where the level of reliability required is now greater than in the past. There has been broad recognition among respected independent professional organizations, federal and local government agencies, businesses, first responders and Homeland Security officials of the critical need to increase the reliability of the electric grid.

- The slow economy's impact on load growth, combined with increased capital investment in infrastructure driven by increased customer expectations and needs around reliability, have had the effect of increasing the frequency of distribution rate increase requests by the Company;

- Numerous stakeholders have expressed concerns over the frequency and cost of rate increase filings that ultimately get passed on to consumers and the ability of consumers to manage unpredictable rate increases in the current economy;

- In its currently pending base rate case, Delmarva testified that in order to address the reliability and system maintenance needs, Delmarva plans to invest $397 million in capital into its system from 2013 through 2017. Staff filed a petition, which led to the opening of the Reliability Docket (Docket No. 13-152) regarding the Company's level of planned investments in reliability and the rate impact those investments may have upon Delmarva's customers.

- Staff has consistently expressed its concern that Delmarva's customers be able to understand the benefits they receive from increased investments in the reliability of the system.

The proposed FLRP is a multiyear rate plan carefully designed to address all of these issues. This filing will demonstrate that the proposed FLRP balances the needs and concerns of customers, the Company, the Commission and the State while achieving the following:

1. Providing Delmarva with the ability to develop a more reliable electric distribution system that meets the needs and expectations of Delmarva's customers and the State of Delaware.

2. Providing more stringent mandatory minimum reliability performance standards that are backed by bill credits to customers if the reliability standards are not met by Delmarva.

3. Providing known, reasonable and manageable distribution rates over a four year period, while reducing the regulatory costs to our customers caused by multiple annual filings.

4. Providing customers with rate predictability not available under the traditional rate making process by establishing what rates will be each year for a future four year rate effective period.

Set forth below are the customer distribution rate impacts of the proposed FLRP. As the attached testimony describes in detail, these rates would include not only the reliability capital investments through 2017, but also the additional non-reliability capital costs, as well as the operations and maintenance expenses needed to maintain and enhance the distribution system through year 2017.

	Year 1	Year 2	Year 3	Year 4
Monthly Total Bill $ Impact[1]	$3.00	$3.85	$1.97	$0.69
Monthly Total Bill % Impact	2.23%	2.80%	1.39%	0.48%
Authorized Return on Equity (ROE)	9.75%	9.75%	9.75%	9.75%
Estimated FLRP Earned ROE	**7.41%**	**8.80%**	**9.75%**	**9.75%**

Table 1 – Typical Residential Customer Bill Impact and Company Return

The table above illustrates that under the FLRP, the typical residential customer would experience bill increases once per year averaging less than $2.40 per month, which equates to an average total bill increase of less than 1.8% per year over the four year FLRP period.[2] While Delmarva recognizes that even moderate bill increases are difficult for some customers, providing reliable and safe electric delivery service comes with costs. As experts and leaders from across the nation and Delaware have expressed, if we do not make these critical electric distribution system infrastructure investments now, customers will pay far higher costs later in the form of damage to the economy, reduced household income, loss of jobs, compromised emergency services, and a higher cost of rebuilding the system in later years. The distribution rate impacts under the proposed Forward Looking Rate Plan (set forth in the table above), if adopted, would achieve all of the benefits discussed above, while resulting in a manageable rate impact on customers.

As the attached testimony provides in greater detail, the FLRP eases the rate impact for customers in the first two years as the Company earns lower than its currently authorized return, while providing more certainty around annual revenue that will enable the Company to continue its critical reliability investments into the system. By years three and four, the Company will have the opportunity to earn its authorized ROE of 9.75%. In addition, in the event the proposed FLRP is accepted, it would serve as a resolution of the currently pending base rate case (Docket No. 13-115) and avoid the filing of another electric base rate proceeding until at least 2017. The incremental cost of conducting an electric rate case proceeding is approximately $650,000 – a cost that is included in customer rates. By avoiding, the cost of rate cases over the four year FLRP period, an additional savings of approximately $2.6 million that would normally be included in rates is also avoided.

In addition to moderate rates, greater efficiencies and critical system infrastructure investments that would arise out of the FLRP, Delmarva proposes that the current Regulatory Docket 50 minimum reliability standard of SAIDI 295 be made more stringent as each year of the FLRP progresses. By the fourth year of the FLRP, the current Docket 50 minimum

1 For a typical residential customer of 1,000 KwH per month.

2 As the testimony reviews in detail, the FLRP applies only to Delmarva Power's distribution rates and, as such, does not affect rates during the four year period related to energy supply or legislatively-mandated programs, such as Renewable Portfolio Standards Compliance.

reliability standard would be SAIDI 179, which is more than 35% more stringent than it is today. In addition, Delmarva has proposed that refunds in the form of bill credits be paid to customers if Delmarva does not meet the stricter minimum reliability standards. Adoption of stricter minimum reliability performance standards backed by refunds to customers is a key element of the FLRP. This element serves to address a pivotal issue of both Staff and the Public Advocate: that customers be able to understand that they are receiving a reliability benefit out of the system infrastructure investments made by Delmarva. Delmarva agrees with Staff and the Public Advocate on the importance of that issue, and, therefore, has made it a central element of the proposed FLRP.

The attached testimonies of witnesses Glenn Moore, Gary Zibinski and Marlene Santacecilia contain the details of the Forward Looking Rate Plan. The FLRP is the result of months of hard work by Staff, the Public Advocate and Delmarva and is designed to provide significant benefits to all stakeholders. Delmarva acknowledges that this filing represents the first opportunity Staff and the Public Advocate will have to review the full details of the proposed FLRP and we look forward to working closely with all stakeholders to review and examine the plan.

Respectfully Submitted,

Todd L. Goodman
Associate General Counsel
Delmarva Power & Light Company

Gary R. Stockbridge
Regional President
Delmarva Power & Light Company

enclosures

DELMARVA POWER & LIGHT COMPANY

BEFORE THE
DELAWARE PUBLIC SERVICE COMMISSION
DIRECT TESTIMONY OF GLENN A. MOORE
DOCKET NO. 13-

Q1. Please state your name and position.

A1. My name is Glenn A. Moore. I am Regional Vice President for Delmarva Power's (Delmarva or the Company) New Castle Region.

Q2. What are your responsibilities in your role as Regional Vice President for Delmarva Power?

A2. I am responsible for external relations in Delmarva's New Castle Delaware Region and Delmarva's participation in the communities it serves. My responsibilities also include establishing and maintaining strong ties with our state and local communities, including corporate philanthropy and community involvement. I am a liaison within the Company on behalf of the customers and communities that Delmarva serves and am accountable to see that Delmarva meets its obligations in the New Castle region.

Q3. Please state your educational background and professional experience.

A3. I hold a Bachelor of Science (1983) and a Masters Degree (1992) in Economics, both from the University of Delaware. I have worked for Delmarva for over 28 years. I started my career at the Company in Corporate Planning, where I was responsible for load and energy forecasting. Other positions include: Analyst in Gas Business, Supervisor of Benefits, HR Strategic Partner in the former Conectiv competitive businesses, Vice President of Operations in Conectiv Communications, and Customer Advocate. I became Vice President of the Delmarva Power Region in 2006.

Q4. What is the purpose of your Direct Testimony?

A4. The purpose of my Direct Testimony is to: (1) explain why the Company has made this filing, (2) explain the history of the Forward Looking Rate Plan (FLRP or the Plan), (3) explain general principles included in the design of the FLRP based on outreach to stakeholders, (4) explain at a high level the concept of the FLRP and its components, (5) provide a comparison between the traditional ratemaking process and the FLRP process, (6) provide a description of the benefits and customer impact of the FLRP, (7) explain how the FLRP relates to the Delaware Public Service Commission's (the Commission) investigation in PSC Docket No. 13-152 (the Reliability Docket), (8) provide an overview of the development of the inputs to The Regulatory Planning Model (the Model) at the foundation of the FLRP, (9) explain what general rules would be needed to administer the FLRP, and (10) introduce the other Company Witnesses.

Q5. Why has the Company made this filing?

A5. The FLRP presents a change from the traditional rate making process used for many years. As explained below, this change would provide significant benefits to customers. A number of events have led the Company to the conclusion that now is the time to consider the benefits of a multi-year or "forward looking" rate plan, including:

- As part of the Commission's approved settlement (the Settlement) in the Company's last electric base rate case (PSC Docket No. 11-528), the Staff of the Public Service Commission (Staff), the Division of the Public Advocate (Public Advocate) and the Company agreed to "discuss alternative regulatory methodologies, including a multi-year rate plan," recognizing that times were changing and other options should be considered;

- Customer research has established that the primary concern of Delmarva's customers, both business and residential, is the reliability of the electric service grid;
- The increased frequency and severity of storms over the last decade, coupled with damage to the regional grid and the economic impact caused by these storms, has resulted in a national recognition of the critical need to make the system less vulnerable to weather-related outages and to reduce the time it takes to restore power after an outage occurs;
- The greater reliance of individuals, businesses, governments, healthcare and emergency services on electricity has developed to the point where the level of reliability required by customers is now greater;
- The slow economy's impact on customer growth, combined with increased capital investment in infrastructure driven by increased customer expectations around reliability, have had the effect of increasing the frequency of distribution rate increase requests by the Company;
- Numerous stakeholders have expressed concerns over the frequency and cost of annual rate increase filings that ultimately get passed on to consumers, and the ability of consumers to manage unpredictable rate increases in the current economy;

- The Staff filed a petition which led to the opening of the Reliability Docket regarding the Company's level of planned investments in reliability;
- In connection with the Settlement, Staff, Delmarva and the Public Advocate agreed to discuss alternative regulatory methodologies that would include, but not be limited to, multi-year rate plans; and
- Staff has consistently expressed its concern that Delmarva's customers be able to understand the benefits they receive from increased investments in the reliability of the electric system.

This filing will demonstrate that the FLRP balances the needs and concerns of customers, the Company, the Commission and the State while doing the following:

1. Providing Delmarva with the ability to develop a more reliable electric distribution system that meets the needs and expectations of Delmarva's customers and the State of Delaware.
2. Providing more stringent mandatory minimum reliability performance standards that are backed by bill credits to customers if the reliability standards are not met by Delmarva.
3. Providing known, reasonable and manageable distribution rates over a four year period by reducing filing costs and developing rates projected to provide Delmarva with a reduced earned return in the first two years of the four year rate effective period, and then adjusting the rate of return for the next two years to provide the Company with the opportunity to earn its currently authorized return on equity (ROE) as established in PSC Docket No. 11-528.

4. Providing customers with rate predictability not available under the traditional rate making process by establishing what rates will be each year for a future four year rate effective period.

Q6. What is the history of discussions to date on the FLRP Concept?

A6. In the Settlement (PSC Docket No. 11-528), the parties agreed to meet and discuss (1) "alternative regulatory methodologies, including a multi-year rate plan" and (2) "the establishment of metrics related to reliability investments so that customers are aware of how investment in Delmarva's plant in service benefits them in a quantifiable manner." Therefore, the Company, Staff, and the Public Advocate began meeting informally and discussing the general design concepts of a FLRP. These discussions spanned several months and included a number of potential components of the Plan, including but not limited to: customer and Company impacts, potential terms and conditions, levels of spending for capital and Operation and Maintenance (O&M) costs, and the concept of more stringent minimum reliability performance standards.

In April 2013, at the request of Staff, the Commission opened the Reliability Docket in order to look more specifically at (1) the future levels of reliability capital investments, (2) minimum reliability service levels, and (3) the impact of reliability investments on rates. Because these three issues are addressed in the proposed FLRP, and given the procedural schedule of the current base rate case in PSC Docket No. 13-115 (the 2013 Base Rate Case) and the Reliability Docket, the Company believes that now is the optimal time to consider adopting the FLRP.

Q7. In seeking input from the Public Advocate, the Staff, and other stakeholders, what general principles were found to be important to include in the FLRP?

A7. I believe that all stakeholders agree that two general principles must be included in the design of a FLRP. First Principle: A plan with stable, reasonable rate impacts to customers that recognize the current economic conditions.

The focus of this principle is to determine a revenue increase that will allow the Company to continue making its planned capital investments, while at the same time: (1) lowering and stabilizing the annual cost increase to Delmarva's customers and (2) providing the Company with the opportunity to achieve its currently authorized ROE of 9.75% within three years. The FLRP consists of a proposed increase in electric delivery revenue in the amount of $56.3 million over four years, which results in the following four year total bill impacts, primarily driven by the associated Company return each year:

	Year 2014	**Year 2015**	**Year 2016**	**Year 2017**
Monthly Total Bill $ Impact [1]	$3.00	$3.85	$1.97	$0.69
Monthly Total Bill % Impact	2.23%	2.80%	1.39%	0.48%
Authorized ROE	9.75%	9.75%	9.75%	9.75%
Estimated FLRP Earned ROE	**7.41%**	**8.80%**	**9.75%**	**9.75%**

Table 1 – Typical Residential Customer Bill Impact and Company Return

Second Principle: Adopting more stringent reliability performance standards which incorporate consequences for not meeting those standards.

[1] For a typical residential customer using 1,000 KwH per month.

The second principle includes making the current Docket 50 minimum reliability performance standards more stringent as the FLRP period progresses and providing for bill credits to Delmarva's customers if those more stringent reliability performance standards are not achieved. This principle assures that customers will realize the benefits associated with the levels of reliability capital investments and system maintenance embedded in the FLRP.

In addition, the Plan establishes the future targeted level of capital and O&M investments before the Company actually makes those investments. This is significantly different than the current rate making process, whereby the Commission primarily reviews Delmarva's expenditures only after they are incurred. Accordingly, the proposed FLRP provides the Commission with the ability to review, regulate and establish rates based upon Delmarva's current and future capital investment plans.

Q8. Can you provide an overview of how the FLRP was developed?

A8. The FLRP represents a balance between the needs of the customer and the needs of the Company, while allowing customers to realize benefits over the traditional rate case process. The two key components of the Plan, closely tied together, are (1) the forward looking Model and (2) the overall balancing of needs between the customer and the Company through the setting of the inputs to the Model. These two components, combined with many comments received from stakeholders, resulted in a plan designed to create a new way of setting rates for Delmarva Delaware that is more reflective of today's needs.

The first component of the Plan is the Model which determines projected customer financial impacts based on fundamental inputs around capital investments, more favorable working environment for the Company. Delmarva conducts extensive customer surveys to determine what its customers want and need. These surveys have consistently shown that the three most important factors to our customers are, in order of importance: (1) reliability, (2) customer service, and (3) reasonable rates. The FLRP, with its improved minimum reliability performance standards and rate predictability, was specifically developed to enable Delmarva to provide customers what they have consistently told us they want.

The second benefit the Company will obtain is a more predictable revenue stream. Even though the FLRP calculates rates to achieve an ROE in the first two years that is below the currently authorized ROE of 9.75%, removing the unpredictable nature of future filings over a span of four years is expected to be viewed favorably by the investment community.

The final benefit is that Delmarva believes that the Plan creates a clear path toward an opportunity for Delmarva to earn its authorized ROE and eliminate regulatory lag in the process. Regulatory lag has been a challenging issue in the utility industry and one that greatly concerns the credit analysts in the industry. I described earlier in my testimony why the reduction of regulatory lag provides significant benefits to both utilities and customers.

Q27. Can you explain the customer benefits of this rate plan?

A27. Customers would see three primary benefits under the FLRP. The first is reasonable and known distribution rates for the next four years. A criticism of traditional regulation from a customer perspective is that rates are not predictable for any length of time, making budgeting difficult for both residential and commercial customers. In contrast, the FLRP provides for known rates for a period of four years into the future. While knowing what utility rates will be is beneficial to residential customers, it is particularly advantageous to commercial customers, as it facilitates better budgeting and planning.

The second benefit for customers is the improved minimum level of reliability to which the Company has committed. The Company agrees to the establishment of more stringent minimum reliability standards: a SAIDI that is 35% more stringent than the current Docket 50 minimum performance standard in year one, and becomes more stringent in each of the three subsequent years of the four year FLRP rate effective period. The specific SAIDI targets were shown earlier in my testimony. The Company also agrees to customer bill credits associated with performance that falls outside of a range around a reliability performance target going forward, as discussed below. The Staff has made it clear that Delmarva's customers need to see quantifiable benefits from the investments Delmarva is making to maintain and enhance the reliability of its system. Delmarva agrees with Staff and as such, developed the FLRP with these more stringent minimum mandatory reliability requirements, backed by bill credits to customers if Delmarva fails to meet the stricter reliability standards.

A third benefit is that the overall cost of the regulatory process is reduced under the FLRP. The incremental cost of conducting an electric rate case proceeding is approximately $650,000. Accordingly, a rate case conducted every year over a four year period would total approximately $2.6 million. That $2.6 million is a cost that is included in rates paid by customers. Because the FLRP would set rates for a period of four years, the savings to customers in avoided regulatory costs alone would be significant. That regulatory cost savings is one more factor that leads to lower rates under the FLRP.

Q28. Can you discuss other benefits besides those seen by the customer and the Company?

A28. Yes. The investment Delmarva is committing to make over the next four years has the potential to create additional jobs in the State, directly and indirectly. In capital alone, the Company will be spending $356 million over the next four years.

In addition, the Company believes that the predictability of future rates is a driver toward economic development. A new business looking to move to Delaware has a clear idea of the costs of future delivery rates for the next four calendar years.

As I mentioned earlier in this testimony, adoption of the FLRP will enable Delmarva to know what the acceptable level of system investment will be over the next four years – providing the Company with the ability to develop a more reliable electric distribution system that meets the needs and expectations of Delmarva's customers, the State of Delaware and the nation. An increasingly reliable electric grid is essential to meeting the rapidly-evolving needs of an increasingly digital society. The increased reliance of individuals, businesses, governments, healthcare and emergency services on electricity has developed to the point where the level of reliability that may have been acceptable even a few years ago is no longer suitable. It is reasonable to expect that our society will continue to become more reliant upon the reliability of the electrical grid as an essential part of their daily lives. Outages that may have been considered more of an inconvenience only a few years ago can stifle commerce almost entirely. Today, when the power is out, computers do not work, communications systems fail, orders do not get taken, stores close, wages are lost, and production shuts down.

At the same time that outages in general have become more problematic to customers, the region is facing storms of increasing strength and frequency. As the U.S. Department of Energy has reported, eight of the largest ten hurricanes have occurred over the past decade. In the last few years alone, Hurricanes Isabel, Sandy and the 2012 Derecho have made clear that the region is facing more frequent and violent storms that have destroyed essential components of the energy infrastructure along the coastal states and have caused enormous economic losses. As storms increase in frequency and intensity, the ability of the Company's electric infrastructure to withstand storms and to restore electricity quickly when disruptions occur will become even more important. Fortunately for Delawareans, the 2012 Derecho and Hurricane Sandy largely spared Delaware, at least compared to the damage suffered by nearby states. For instance, Maryland and New Jersey were battered by the Derecho and parts of New Jersey and New York were devastated by Hurricane Sandy. Delmarva should not wait until Delaware gets impacted by storms the way our neighboring states did before the Company acts to strengthen its system.

Q29. Can you explain the relationship between the Reliability Docket and the FLRP filing?

A29. The Company sees a close relationship between the FLRP and the ongoing Reliability Docket. The Reliability Docket is designed to examine (1) what the right level of infrastructure investment going forward should be, and (2) what the rate impact of the future capital budget described in the Company's 2013 Base Rate Case will have on Delmarva's customers. The Company envisions the FLRP as a solution to those two questions that lays out specific levels of investments, coupled with minimum standards for improved reliability performance, and a specific rate impact for not only infrastructure investments but all capital and O&M investments of the Company over a four year period. There are, however, some specific differences between the two discussed below.

The Reliability Docket is focused on very specific components of the Company's overall capital expenditures (infrastructure investments) over the five year period from January 1, 2012 to December 31, 2017. The Reliability Docket does not include general capital expenditures such as information technology investments (other components), nor were O&M expenditures included. The FLRP includes all capital and O&M expenditures by the Company over a four year period between October 1, 2013 and September 30, 2017.

The general concerns around appropriate levels of infrastructure spending, customer feedback, the impacts on the bill of various levels of investments, and the implications of over or under investing in the infrastructure are themes that are consistent between the FLRP and the Reliability Docket. The Company sees the FLRP as directly responsive to many, if not all, of the issues raised in the Reliability Docket to date.

The Company made several key points in the first of three public meeting presentations in the Reliability Docket that point to the FLRP as a sound path forward. These include:

- Customer needs, changing weather patterns, aging infrastructure, and technology advances are driving higher levels of infrastructure investment than in the past;
- The Company has begun to act on these needs by stepping up investments and proposes to continue with these investments over the next several years;
- Other reports referenced in the presentation indicate there is a significant potential cost to the community for inaction on reliability infrastructure investments;
- Although the Company has made significant advances on its key reliability measure (SAIDI), Delmarva still ranks in the third quartile as compared to other utilities in industry benchmarks, signifying the continued need to improve its infrastructure; and
- The impact for all capital and O&M requirements over the next four years (when looking at the FLRP filing) maintain a total overall bill impact of less than 2% per year for the typical residential customer. Although any impact is important to the Company's customers, this is a reasonable impact compared to the potential cost to the community of not investing in infrastructure.

In summary, the FLRP provides a sound path forward regarding the issues raised in the Reliability Docket proceedings.

Q30. Can you introduce each of the Company witnesses and briefly explain the purpose of their testimony?

A30. Company Witness Gary M. Zibinski describes the Model and explains how it was used to develop the FLRP.

Company Witness Marlene C. Santacecilia provides the rate design supporting the Company's proposed increase in electric delivery revenue in the amount of $56.3

million over four years. The proposed rate design incorporates the results from the FLRP.

Q31. Does this conclude your Direct Testimony?

A31. Yes, it does.

DELMARVA POWER & LIGHT COMPANY

BEFORE THE
DELAWARE PUBLIC SERVICE COMMISSION
DIRECT TESTIMONY OF GARY M. ZIBINSKI
DOCKET NO. 13-

Q1. Please state your name and position.

A1. My name is Gary M. Zibinski. I am a Manager of Regulatory Planning in the Regulatory Affairs Department of Pepco Holdings Inc. (PHI). I am testifying on behalf of Delmarva Power & Light Company (Delmarva or the Company).

Q2. What is your educational background?

A2. I hold Bachelor of Science degrees in Finance and in Accounting from Drexel University. I also hold a Master of Science degree in Finance from Drexel University.

Q3. Please describe and summarize your employment experience in the utility industry.

A3. I began my career with Associated Utility Services, Inc. as a Financial Analyst in 1978. I joined Delmarva in 1988. Since then, I have held numerous positions including Manager- Financial Analysis and Budgets and Manager-Strategic Planning. In 2005, I joined the Regulatory Affairs department as a Manager-Regulatory Planning and Finance. In this position, I am responsible for supporting regulatory planning activities and projects and supporting the calculations of utility cost of capital and capital structure.

Q4. Have you filed testimony in any other proceedings?

A4. Yes. I have previously presented and/or filed testimony as a witness before the Delaware Public Service Commission, the New Jersey Board of Public Utilities,

PUC DOCKET NO. 33309
SOAH DOCKET NO. 473-07-0833

APPLICATION OF AEP TEXAS CENTRAL COMPANY FOR AUTHORITY TO CHANGE RATES	**§ § §**	**PUBLIC UTILITY COMMISSION OF TEXAS**

ORDER ON REHEARING

On November 9, 2006, AEP Texas Central Company (TCC) filed an application for authority to change rates pursuant to PURA,[1] Chapter 36, requesting an increase in base rates that would produce an annual base revenue increase of $62,709,174. During the course of this proceeding, TCC reduced this amount to approximately $49,952,000.[2] TCC also seeks to terminate the merger savings and rate reduction riders implemented in Docket No. 19365,[3] further increasing its revenues by $19,988,359 annually. Therefore, the total revenue increase sought by TCC in this proceeding is $69,940,359.

The administrative law judges (ALJs) filed a proposal for decision (PFD) on August 30, 2007. In their PFD, the ALJs recommend that the Commission approve TCC's application, including termination of the merger savings and rate reduction riders, subject to the adjustments recommended in the Proposal for Decision (PFD). The recommendations reduce TCC's adjusted test year total revenue requirements from $581,127,359 to $531,123,478, a reduction of $50,004,479. TCC identified several number-run adjustments required to implement the ALJs' decision.[4] The Commission ordered Commission Staff to incorporate TCC's number-run corrections, which resulted

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[1] Public Utility Regulatory Act, TEX. UTIL. CODE ANN. §§ 11.001 – 64.158 (Vernon Supp. 2007) (PURA).

[2] TCC Ex. 78, RWH-1R.

[3] *See Application of Central and Southwest Corporation and American Electric Power Company, Inc. Regarding Proposed Business Combination,* Docket No. 19365, Integrated Stipulation and Agreement (Nov. 18, 1999).

[4] AEP Central Company's Exceptions to the Proposal for Decision and Request for Number Running Corrections, Attachment E at 87-91(Sept. 20, 2007).

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in a revenue requirement of $540,707,774 or a reduction of $40,419,575[5] from TCC's original request. The Commission adopts the PFD issued by the ALJs, including the findings of fact and conclusions of law, with the number run corrections recommended by TCC in its exceptions to the PFD.[6] Findings of fact 23, 24 and 42 are modified to reflect Commission Staff's updated number runs.

I. Findings of Fact

Procedural History

1. AEP Texas Central Company (TCC or the Company) is an electric utility operating company and wholly owned subsidiary of American Electric Power Company (AEP), a public utility holding company.

2. TCC has been functionally unbundled, and its costs have been separated for accounting purposes among Transmission, Distribution, and Generation functions since the onset of retail competition in 2002.

3. TCC filed its application with the Public Utility Commission of Texas for authority to increase its transmission and distribution (T&D) rates on November 9, 2006, requesting an overall increase of approximately $62.7 million.

4. As part of its application, TCC gave notice of its intent to terminate approximately $20 million in credits to customers that are provided by separate riders implemented in connection with the Commission's approval of the AEP/CSW merger in *Application of Central and Southwest Corporation and American Electric Power Company, Inc. Regarding Proposed Business Combination*, Docket No. 19265 (Nov. 18, 1999).

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[5] *See generally* Commission Staff Final Number Run - Final Order - Schedule 1 - Total Revenue Requirement - Column Total for *Final Order Adjusted Total Electric* (Feb. 5, 2008).

[6] *See generally* Corrected Page to the Proposal for Decision and Request for Number Running (Sept. 20, 2007).

5. Concurrent with its filing with the Commission, TCC filed a similar petition and statement of intent with each incorporated city in its service area that has original jurisdiction over its retail rates.

6. Notice of TCC's application was published once a week for four consecutive weeks in newspapers having general circulation in each county in TCC's service territory and was completed on December 14, 2006.

7. Individual notice of the TCC's application was provided on November 9, 2006, to the Commission Staff and the Office of Public Utility Counsel (OPC).

8. On October 4, 2006, TCC mailed notice to each municipality in TCC's service area of its intent to change rates charged to retail electric providers (REPs) and certain end-use customers.

9. On November 8, 2006, TCC mailed notice of its petition and statement of intent to each municipality within TCC's service area.

10. Individual notice of the TCC's application was provided and completed by November 9, 2006, to all REPs who have been certified by the Commission and who serve end-use customers in TCC's service area. Notice was provided to all certified REPs.

11. Individual notice of the Application was provided to each party that participated in *Application of AEP Texas Central Company for Authority to Change Rates*, Docket No. 28840 (Aug. 15, 2005), TCC's last T&D rate case.

12. The Commission referred this proceeding to the State Office of Administrative Hearings (SOAH) on November 14, 2006. The Commission issued its Preliminary Order setting forth the issues to be addressed in this proceeding on December 19, 2006.

13. The following parties were granted intervention: Alliance for Retail Markets (ARM); Cities served by TCC (Cities); City of Garland; Commercial Customer Group (CCG); CPL Retail Energy, L.P. (CPL); Efficiency Texas; Federal Executive Agencies (Department of the Navy); Occidental Power Marketing, L.P.; OPC; Reliant Energy Retail Services, LLC; South Texas Electric

Cooperative; Sharyland Utilities, L.P.; State of Texas; Texas Cotton Ginners' Association; Texas Industrial Energy Consumers (TIEC); Texas Legal Services Corporation (TLSC); Texas Ratepayers Organization to Save Energy (Texas ROSE); Texas State Association of Electrical Workers; Oncor Electric Delivery Company; TXU Energy, Wholesale and Power Companies; and Wal-Mart Stores Texas, L.P. and Texas Retail Energy LLC (Wal-Mart).

14. TCC timely filed appeals with the Commission of the rate ordinances of the municipalities exercising original jurisdiction within its service territory. All such appeals were consolidated for determination in this proceeding.

15. TCC's application is based on a test year ending June 30, 2006.

16. On January 26, 2007, TCC filed an update to its rate filing that reduced its overall rate increase request by approximately $1.6 million.

17. When TCC filed its rebuttal case, it unilaterally decreased its total requested T&D base rate increase to approximately $50 million, a reduction of approximately $12 million from its initial request. This reduction included the impact of the January 26, 2007 update, as well as other reductions agreed to by the Company as a result of changed circumstances since its initial filing, or based on its review of Commission Staff and intervenor positions.

18. The hearing on the merits commenced on April 12, 2007 and lasted seventeen hearing days, concluding on May 4, 2007.

19. TCC proposed an effective date of December 14, 2006, for the proposed rates. The effective date was suspended for 150 days until May 13, 2007. The Company agreed to further extend the effective date in order to allow the ALJs and the Commission to process the case.

20. On April 17, 2007, TCC filed notice of its intent to put into effect, under bond, the rates set out in attached, filed tariff sheets. The rates will produce an annual base revenue increase of $50,061,000. TCC stated its intent to implement such bonded rates on a system-wide basis on or after May 30, 2007, in order to maintain uniform system-wide rates throughout its service territory.

21. On May 15, 2007, the ALJs issued an interim order finding that a bonded rate is a changed rate under the ISA and PURA § 36.110; therefore, TCC is allowed to terminate the merger savings and the rate reduction riders ordered in Docket No. 19265, upon implementation of bonded rates.

22. On June 27, 2007, the Commission denied an interim appeal of the order identified in the above finding of fact 21, affirming the ALJs' ruling.

Rate Base

23. TCC's used and useful total transmission plant in service (excluding general and intangible plant in service) is $912,831,763.[7] TCC's used and useful transmission plant in service net of accumulated depreciation (excluding depreciation on general and intangible plant in service) is $642,951,403.[8]

24. TCC's used and useful total distribution plant in service (excluding general and intangible plant in service) is $1,446,115,221.[9] TCC's used and useful distribution plant in service net of accumulated depreciation (excluding depreciation on general and intangible plant in service) is $953,628,481.[10]

25. TCC included in rate base a pension prepayment asset of $112.4 million.

26. The pension prepayment asset arises under Generally Accepted Accounting Principles (GAAP) in accordance with Statement of Financial Accounting Standards No. 87 (SFAS 87) and represents the amount by which the pension fund exceeds the accumulated pension obligations.

27. Investment income on the pension prepayment asset reduces pension cost calculated under SFAS 87.

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[7] *See* Docket No. 33309 - Final Order Number Run - (Transmission Model) Schedule II-B-1, Rate Base Accounts - Plant Test Year Ending 6/30/2006 - Total Transmission Distribution Plant Gross (Filed February 5, 2008)

[8] *Id.*- Schedule II-B-5 - Total Transmission - Distribution Plant - Net

[9] *Id.* (Distribution Model) Schedule II-B-1

[10] *Id.* (Distribution Model) Schedule II-B-5

28. Accounting in accordance with GAAP requires that both the balance sheet and income statement effects be taken into account.

29. The pension prepayment asset contains $22.799 million included in construction work in progress (CWIP).

30. Only the non-CWIP portion of the income earned on the pension prepayment asset is reflected in the total pension expense and the revenue requirement.

31. The pension prepayment asset should not be included in TCC's rate base to the extent that TCC's pension cost is capitalized to CWIP.

32. The pension prepayment asset of $112.4 million, less the $22.799 million portion included in CWIP, should be included in rate base.

33. All of TCC's operations and maintenance (O&M) and administrative and general (A&G) expenses are included in its cash working capital calculation.

34. The leads and lags in paying these items, which give rise to the amounts recorded in Account 190, have been appropriately included in the calculation of rate base through this process.

35. Accumulated Deferred Federal Income Tax (ADFIT) of $323.9 million is reasonable and should be included in rate base.

36. In arriving at its adjusted test-year-end rate base, TCC reclassified $7.3 million in transmission projects that were classified as CWIP and that had not been closed out to plant-in-service as of June 30, 2006 but which were actually providing service to customers as of that date.

37. TCC also removed from rate base allowance for funds used during construction (AFUDC) of $368,625 related to the transmission projects that were reclassified.

38. The $7.3 million reclassification of these projects to plant-in-service is reasonable and should be adopted.

39. TCC's construction accounts payable were included in TCC's cash working capital calculation. Accordingly, the leads and lags associated with these

construction accounts payable are appropriately included in the calculation of rate base.

40. Based on findings of fact 72 through 77, TCC's affiliate capital costs assigned to TCC Distribution should be reduced by $2,454,762, and affiliate capital costs assigned to TCC Transmission should be increased by $211,520.

41. TCC included in rate base $10.2 million in debt restructuring costs related to business separation. TCC also included in cost of service an annual amortization expense of $914,892 for amortization of these debt restructuring costs over a 15-year period.

42. TCC has a current cash working capital requirement of ($2,341,171), which includes $1,361,010 for transmission; ($2,660,226) for distribution; ($478,450) for metering; and ($563,505) for TDCS.[11]

43. TCC's current working capital request reflects a modification of the monthly payment dates from TCC to American Electric Power Service Corporation (AEPSC) from the actual date of payment (usually the second or third working day after receipt) to the thirtieth day after receipt of the bill, as authorized by the TCC-AEPSC Service Agreement.

44. TCC must pay additional AEPSC financing costs for delaying payment of its bill from the second or third day until the thirtieth day after receipt.

45. TCC's own financing costs equal the financing costs charged to it by AEPSC. Thus, TCC will save the same amount of financing costs that AEPSC will charge it for delaying payments to AEPSC, so TCC will not incur any net increase in finance charges by delaying payment to AEPSC.

46. For TCC's cash working capital calculation, it is more appropriate to use the mid-point of the service period than the invoice date in the calculation of third-party expense lead days.

[11] *See* - P.U.C. Docket No. 33309 - Final Number Runs - Schedule IIB - Summary of Rate Base - Cash Working Capital (Reference Schedule II-B-9) Page 1 of 1 (February 5, 2008).

47. Cities' calculation of the third-party payment lead from samples of TCC's third-party invoices is reasonable and should be adopted, resulting in an additional third-party expense lead period of 2.26 days for distribution and an additional third-party expense lead period of 5.63 days for transmission.

48. The additional lead days for third-party expenses reduces TCC's request for cash working capital and rate base by $9,314,603.

49. Beginning with calendar year 2005, TCC was required to implement for financial reporting purposes accounting for legal asset retirement obligations (AROs) associated with the cost of removal of asbestos from buildings in accordance with SFAS 143.

50. In its filing, TCC incorporated appropriate accounting changes for ratemaking purposes to account for the AROs associated with the cost of removal of asbestos from buildings in accordance with SFAS 143. This involved the establishment of offsetting ARO assets and liabilities, the inclusion of SFAS 143 depreciation and accretion in cost of service, and the exclusion of the cost of removal of asbestos from buildings from the net salvage component of the calculation of depreciation rates for Account 390.

51. TCC's use of SFAS 143 accounting for ratemaking purposes for the cost of removal of asbestos from buildings aligns the regulatory treatment with GAAP and should be approved.

Return on Equity and Capital Structure

52. A return on equity of 9.96% will allow TCC a reasonable opportunity to earn a reasonable return on its capital investment.

53. TCC's energy conservation efforts, the quality of its services, the efficiency of its operations, and the quality of its management support a 9.96% return on equity.

54. A 9.96% return on equity is consistent with the level of financial risk associated with TCC's capital structure.

55. A reasonable application of the discounted cash flow, risk premium, and capital asset pricing models supports a return on equity of 9.96%.

56. TCC presented a revised pro forma cost of debt of 5.8586% based on updated information resulting from the retirement and refunding of its debt using the proceeds of the securitization approved in *Application of AEP Texas Central Company for a Financing Order*, Docket No. 32475, Financing Order (June 21, 2006).

57. The $1,669,612 in debt issuance costs related to Matagorda Navigation District No. 1 Pollution Control Bonds Series 2005 and B in 2005 were not incurred in connection with the issuance of transition bonds and are properly included in the cost of debt calculation in this docket.

58. TCC could not have included the $1,669,612 in cost of debt in Docket No. 33541, because that docket was a proceeding expressly designed for addressing only qualified costs.

59. TCC's cost of debt for purpose of this docket is 5.8586%.

60. The appropriate capital structure for purposes of setting rates in this proceeding consists of 60% debt and 40% equity.

61. A 60/40 capital structure is consistent with existing Commission precedent for T&D utilities.

62. A 60/40 capital structure is consistent with current rating agency expectations for TCC.

63. TCC's overall rate of return is as follows:

Component	% of Total Capitalization	Cost of Capital Rate	WACC (%)
Long Term Debt	60.00%	5.8586%	3.5152%
Common Equity	40.00%	9.9600%	3.9840%

Total	100.00%		7.4992%

Cost of Service

64. AEPSC is the service company for the AEP System. It provides services to AEP's utility companies, including TCC.

65. TCC provided evidence supporting the primary allocation factors used to allocate costs and why such allocation factors are appropriate for the cost they support for fourteen classes of service involving affiliate transactions between AEPSC and TCC: customer service, distribution; transmission; external affairs; regulatory; Texas administration; information technology; business logistics; human resources; finance; accounting and strategic planning; internal support; safety and environmental; legal; and corporate communications.

66. TCC established cost trends, budget comparisons, benchmark studies, if available, or other proof suggested by the Commission's rate filing package Guiding Principles to support its level of requested affiliate costs.

67. TCC provided a schedule that shows how each allocator used by TCC is calculated and how often the calculation is updated.

68. The functions performed by AEPSC allow TCC to reduce its costs by capturing economies of scale.

69. AEPSC has been consistently reducing service company costs over the last several years, including costs to TCC.

70. The activities performed for TCC are necessary and provide direct benefits to TCC and its customers in terms of lower costs and reliable operations.

71. Of the approximately 90 discrete activities that define the full scope of AEPSC services, 19 activities were assessed to determine the potential for overlap of activities between AEPSC and TCC and other AEP utility subsidiaries. These 19 areas had activity descriptions that indicated potential similarity. Detailed assessment of these activities established that there was no duplication between AEPSC and TCC.

72. The manner in which AEPSC charges costs to TCC is properly designed to ensure that the equitable distribution and the allocation process are generally reasonable, except for the use of TCC's total assets allocator.

73. TCC uses a total assets factor to allocate the cost of certain services provided to itself and to other AEP affiliates by AEPSC.

74. After deregulation pursuant to Senate Bill 7, the Commission quantified TCC's stranded costs, and TCC chose to recover those costs through the securitization process rather than through a competition charge. The Commission issued financing orders allowing TCC to issue securitization bonds, providing TCC with the full amount of its stranded costs. Once the Commission issued the financing orders, TCC placed these regulatory assets on its books, assigned to TCC Distribution.

75. TCC included the regulatory assets noted in the above finding of fact and relating to stranded costs and securitization of generation assets in Allocator 58, its total assets allocator.

76. The inclusion of regulatory assets in Allocator 58 inflates the allocation of costs charged by AEPSC to the TCC distribution company.

77. Although TCC is required by accounting standards to include its regulatory assets on its balance sheet, these regulatory assets are not related to the provision of distribution service and should not be included in TCC's cost of service.

78. TCC adequately reviews and questions the monthly services bill that it receives from AEPSC.

79. Any corrections requested by TCC or by other AEP affiliates, which AEPSC adopts, are applied to bills for all affiliate companies. Thus, a correction requested by another affiliate can benefit TCC.

80. TCC's adjustment to account for the creation of a new affiliate, Electric Transmission Texas, LLC (ETT) is reasonable.

81. TCC's adjustment to Allocator 70, Non-Electric Other Accounts Receivable, is reasonable.

82. TCC's inclusion of annual and long-term incentive compensation related to financial incentives in cost of service is unreasonable because it is not necessary for the provision of T&D utility services.

83. TCC reasonably determined group life insurance expense using an annualized June 2006 amount, with proper adjustments to cost of service to eliminate the portion of capitalized costs.

84. TCC reasonably determined savings plan (401k) expense using an annualized June 2006 amount, with proper adjustments to cost of service to eliminate the portion of capitalized costs, as adjusted in its rebuttal testimony.

85. TCC's pension expense of $1,627,376, which reflects a reduction of $456,000 for negative pension expense under SFAS 87 related to former generation employees, is reasonable and necessary.

86. TCC's requested adjusted test-year amount of $5,953,937 for postretirement benefits under SFAS 106, which included $886,264 in SFAS 106 transition adjustment amortization related to former generation employees, is reasonable.

87. Additional SFAS 106 postretirement benefit costs of $564,736 related to the former generation employees should be included in cost of service.

88. Total SFAS 106 postretirement benefit costs of $6,518,673 are reasonable and necessary.

89. A catastrophic property damage loss self-insurance program with an annual accrual of $1,300,000 and a target reserve amount of $13 million is in the public interest.

90. TCC's distribution O&M expenses, with the removal of the payment to the Public Utilities Board of Brownsville from distribution station maintenance expense, are reasonable and necessary.

91. TCC's transmission O&M expenses are reasonable and necessary.

92. TCC's request to recover the amount of its calendar year 2006 energy efficiency costs is known and measurable because TCC has used the actual 2006 costs to calculate its energy efficiency goal to be achieved by January 1, 2008.

93. For energy efficiency cost recovery, it is more reasonable to use costs incurred in a calendar year because such recovery more closely tracks statutory and regulatory energy efficiency goals.

94. It is reasonable for TCC's cost of service to include $6,334,949 in energy efficiency costs, as reflected in its calendar year 2006 costs.

95. TCC's proposed net salvage values for all FERC accounts are reasonable and appropriate estimates of future net salvage recoveries.

96. In its application, TCC submitted a depreciation study based on plant-in-service as of December 31, 2005. This study reduced TCC's depreciation rates relative to the rates adopted by the Commission in Docket No. 28840.

97. TCC accepted Cities' recommended service life and survivor curves for two FERC accounts and net salvage for one FERC account. Differences exist between TCC and Cities and/or Commission Staff with respect to service life and survivor curves for seven FERC accounts and with respect to net salvage for 20 FERC accounts.

98. TCC's service life and survivor curves, as modified by the above finding of fact, are reasonable and should be adopted for all FERC accounts, except FERC accounts 365, 368, 371, and 373.

99. Commission Staff's recommendations should be adopted regarding the survivor curves (but not its proposed net salvage values), and the resultant depreciation rate should be adopted for FERC accounts 365, 368, and 371.

100. Cities' recommendation regarding the survivor curve and depreciation rate for FERC account 373 is reasonable and should be adopted.

101. TCC properly removed net proceeds from 1999 and 2005 building sales from consideration of net salvage value regarding FERC Account 390, because the net

salvage received from sales of various buildings in those years were not generated in the ordinary course of TCC's business.

102. The inflation embedded in TCC's historical information will likely be experienced in the future.

103. TCC's historical information regarding cost and retirements of its assets properly imposes costs on the customers who benefit from the use of those assets.

104. The depreciation rates requested by TCC as set forth in TCC Exhibit 66 are reasonable and should be approved for all FERC accounts except FERC accounts 365, 368, 371, and 373. TCC's depreciation rates should be applied to the adjusted plant-in-service as of June 30, 2006, in order to calculate the reasonable and necessary depreciation accrual expense for cost of service.

105. The survival curves and resultant depreciation rates recommended by Commission Staff (but not its net salvage values) are reasonable and should be approved for FERC accounts 365, 368, and 371. The depreciation rates resulting from the survival curve recommended by Commission Staff should be applied to the adjusted plant-in-service as of June 30, 2006, in order to calculate the reasonable and necessary depreciation accrual expense for cost of service in FERC accounts 365, 368, and 371.

106. The survival curve and resultant depreciation rate requested by Cities is reasonable and should be approved for FERC Account 373. The depreciation rate resulting from the survival curve requested by Cities as set forth in TCC Exhibit 66 should be applied to the adjusted plant-in-service as of June 30, 2006, in order to calculate the reasonable and necessary depreciation accrual expense for cost of service in FERC account 373.

107. Regarding sales of certain buildings in FERC Account 390, TCC removed from its depreciation study the proceeds from sales in 1999 and 2005, along with the associated costs of removal, and the original costs of the buildings.

108. The approach TCC used regarding sales of buildings in FERC Account 390 is reasonable, comports with the applicable accounting requirements, and provides

the full benefit of the sale, including the gain, to customers, through reduction of rate base and associated reduction of the depreciation accrual.

109. TCC experienced 50% or higher net salvage results for FERC Account 390 in six of 22 years (1984-2005) included in its depreciation study.

110. After 1999, 2005 was the first year in which TCC received net gains from salvage of buildings in FERC Account 390 that exceeded 50%.

111. The last year that a net salvage rate of greater than 50% occurred for FERC Account 390 was 1994.

112. TCC's net salvage results for 1999 and 2005 from sales of buildings are not likely to recur regularly on the same scale.

113. As part of its implementation for ratemaking purposes of SFAS 143 ARO accounting for the legal obligations related to costs of removal of asbestos from buildings, TCC included an accretion expense of $73,000, which substitutes for the cost of removal of asbestos previously included in the cost of removal for depreciation purposes.

114. Because it is reasonable to implement for ratemaking purposes SFAS 143 ARO accounting for the legal obligations related to costs of removal of asbestos from buildings, the related accretion amount is reasonable and necessary.

115. TCC appropriately collected late payment charges in compliance with the existing tariff, using reasonable accounting practices.

116. During the test year, TCC performed transmission-related construction services, engineering, procurement, and other related construction services for the Lower Colorado River Authority (LCRA) on lines that will be owned by LCRA.

117. TCC is exiting the third-party construction business; thus, it reduced its test year margins (revenues less expenses) of $3.3 million down to $789,714, as a known and measurable adjustment to miscellaneous revenues.

118. TCC's adjustment to miscellaneous revenues to account for the decrease in third-party margins is reasonable, known, and measurable.

119. TCC is a member of an affiliated group eligible to file a consolidated federal income tax return.

120. The amount of the fair share of consolidated federal income tax savings allocated to TCC is $1,901,184 before gross up and $2,924,898 after gross up.

121. Ad valorem property taxes in the amount of $27,853,898 are reasonable and necessary expenses.

122. The transmission cost of service (TCOS) included in the final distribution cost of service should be synchronized with the transmission rates applied to the TCC distribution function based on the TCOS established for the TCC transmission function as a result of this case.

123. TCC's historical actual bad debt cost for the test year of $138,776 should be included in cost of service.

124. TCC's proposal to include $328,009 in rates for business and economic dues was unsupported by the preponderance of the evidence because some dues may have included legislative advocacy or lobbying expenses.

125. It is reasonable to sever from this proceeding issues related to Cities' and TCC's recovery of rate case expenses.

Load Research

126. In *Application of AEP Texas Central Texas Company for Authority to Change Rates*, Docket No. 28840 (Aug. 15, 2005), TCC was ordered to file TCC-specific load research data in its next rate case.

127. TCC filed company-specific load research data in this case.

128. TCC employed industry-accepted standard load research practices in developing the load research samples and demand estimates, which accurately represent the TCC rate class populations.

129. The overall result of TCC's load research study is a reasonable estimate of class demands for use in allocating costs in this case.

130. The changed load characteristics result from class usage changes.

131. The final numbers produced by TCC's load research study consistently represent the customers that moved from the non-interval data recorder (IDR) class to the IDR class as if they were members of the IDR class for the entire test year.

Cost-of-Service Study

132. In Docket No. 28840, the Commission's Order required TCC to perform a new distribution field study. TCC completed that study and used its results to allocate demand related distribution costs in the cost-of-service study used in this docket.

133. The cost-of-service studies performed by TCC were performed in a manner that is consistent with that used in TCC's most recent rate case, are reasonable, and should be approved.

134. It is appropriate to use a 100% demand allocator for distribution accounts 364 through 368.

135. The data in the cost-of-service study supporting the development of charges for IDR metered customers, the schedules, and workpapers collectively support the changes proposed by TCC for IDR metered customers.

136. All customers within a class pay the same metering charge, regardless of the type of meter they use.

137. IDR-metered customers receive a higher Customer Charge than non-IDR-metered customers in the same class, primarily due to the complexity of preparing the IDR-metered customer's bill.

Rate Design

138. TCC's rate design uses the same customer classes ordered by the Commission in Docket No. 22344, Order No. 40.

139. TCC's proposed textual changes and changes to the standard allowance values in the Facilities Extension Schedule are unopposed and are reasonable.

140. TCC's proposed pilot program for front-of-the-lot subdivisions, as modified by Commission Staff, is reasonable.

141. TCC's request to continue to provide facilities rental services under the Distribution Voltage Facilities Rental Service and System Integral Facilities Rental Service tariff schedules, as updated in this proceeding, until January 1, 2011, is unopposed and is reasonable.

142. The increases assigned to each of the generic rate classes are the result of moving each rate class to unity (*i.e.*, an equalized rate of return or full recovery of allocated costs).

143. Applying an across-the-board increase when actual cost data is available is contrary to Commission precedent, unjustified, and should be rejected.

144. An adjustment to the revenue allocation for the intra-class functions is neither necessary nor appropriate.

145. Modification of the customer service, metering, and distribution function revenue requirements unjustifiably strays from the equalized cost-of-service study.

146. TCC's proposed changes to the customer charges are based on cost, are consistent with Commission precedent, and should be approved.

Riders

147. TCC's proposed Municipal Franchise Fee Adjustment–City (MFFA-C) rider would be used to reflect a change to a specific municipality's franchise fee.

148. Under the proposed MFFA-C rider, municipal franchise fee adjustment that applies to a specific municipality would be applied to bills of retail customers who are located within the specific city's municipal limits.

149. TCC's proposed Rider MFFA-C should be rejected as it would create confusion with potentially over 100 different rates.

150. Having different rates in each municipality in TCC's service territory is contrary to the Commission's desire for uniform, simple rates.

151. The Commission has a pending rulemaking to change the energy efficiency rules in *Amendments to Energy Efficiency Rules and Templates*, Project No. 33487, which was put on hold pending proposed legislation.

152. It is premature to adopt a new method of energy efficiency cost recovery, such as the rider TCC proposed in its application, until the Commission adopts new rules, as required by recent legislation.

Discretionary Service Fees

153. Discretionary service fees are billed to the REPs or distribution end-use retail customers for the cost of performing a specific distribution service requested by the REP or end-use retail customer.

154. Discretionary service fees are charged to the party that causes the cost to be incurred so that other parties not requiring the service do not have to pay for the cost through base rates.

155. All TDUs must offer the discretionary services defined in the Standardized Discretionary Services Section of the Tariff.

156. TCC's proposed discretionary service fees are based on the cost to perform each discretionary service.

157. TCC's proposed discretionary fees, including the disconnect and reconnect fees, are reasonable and should be approved.

Tariff Formatting and Language

158. Several areas in TCC's filed Standardized Discretionary Services portion of its tariff do not conform to the pro forma tariff approved in Project No. 29637.

159. The formatting changes recommended by Commission Staff should be made in order to comply with the Commission's rule.

160. Commission Staff's recommended changes to the proposed Broken Meter Seal and After Hours Temporary Removal fees should be made.

161. Commission Staff's recommended language changes to Section 6.2.3.3.7, Meter Enclosure Seal Breakage, should be approved.

Termination of the ISA Riders

162. Pursuant to the ISA entered in Docket No. 19265, the merger savings and rate reduction riders related to the merger of AEP and Central and Southwest Corporation (CSW) terminate with a change in TCC's rates.

163. TCC was allowed to terminate the Docket No. 19265 merger savings and rate reduction riders upon its filing of bonded rates, effective May 30, 2007.

164. TCC should continue to be allowed to terminate the Docket No. 19265 merger savings and rate reduction riders upon the entry of a final order in this proceeding that changes TCC's rates.

II. Conclusions of Law

1. TCC is an electric utility as defined by PURA § 31.002, and, therefore, it is subject to the Commission's jurisdiction under PURA §§ 32.001, 33.051, and 36.102.

2. TCC is a T&D utility as defined in PURA § 31.002(19).

3. SOAH has jurisdiction over all matters relating to the conduct of the hearing in this case, including the preparation of a Proposal for Decision, pursuant to PURA § 14.053 and TEX. GOV'T CODE ANN. § 2003.049(b).

4. TCC provided adequate notice of this proceeding in compliance with P.U.C. PROC. R. 22.51.

5. Pursuant to PURA § 33.001, each municipality in TCC's service area that has not ceded jurisdiction to the Commission has jurisdiction over the Company's

application, which seeks to change rates for distribution services within each municipality.

6. The Commission has jurisdiction over an appeal from a municipality's rate proceeding pursuant to PURA § 33.051.

7. PURA § 36.110 authorizes a utility to put changed rates, not to exceed its proposed rates, into effect in all areas in which the utility sought to change its rates under bond if the Commission fails to make its final determination before the 151st day after the date that the proposed change would otherwise have gone into effect had the operation of the proposed rates not been suspended. TCC's proposed effective date for its proposed rates was December 14, 2006, because TCC was authorized to implement a changed rate under bond effective with usage beginning on May 14, 2007, subject to refund, because the Commission did not make its final determination of rates on or before May 13, 2007.

8. The effective date of the change in rates approved in this case was extended to be consistent with P.U.C. SUBST. R. 25.241(i) and by agreement of TCC, consistent with P.U.C. PROC. R. 22.33(c).

9. The rates approved in this proceeding are based on original cost, less depreciation, of property used and useful to TCC, consistent with PURA § 36.053.

10. TCC's treatment of its debt restructuring costs conforms to the determinations the Commission made regarding these costs in its orders in *Application of Central Power and Light Company for Approval of Unbundled Cost of Service Rate Pursuant to PURA § 39.201 and Commission Substantive Rule 25.344*, Docket No. 22352 (Oct. 5, 2001) and Docket No. 28840 (Aug. 15, 2005), should be approved.

11. PURA § 36.065(a) provides that electric utility rates shall include "expenses for pensions and other postemployment benefits, as determined by actuarial or other similar studies in accordance with generally accepted accounting principles, in an amount the regulatory authority finds reasonable."

12. TCC's requested pension expense, which accounts for negative pension expense under SFAS 87 related to former generation employees, is in accordance with PURA § 36.065.

13. TCC's requested adjusted test-year amount of postretirement benefits under SFAS 106, which included a transition adjustment amortization related to former generation employees, is in accordance with PURA § 36.065.

14. GAAP, with respect to pension cost, are determined in accordance with SFAS 87 and SFAS 88.

15. P.U.C. SUBST. R. 25.231(c)(2)(D) prohibits including in rate base the portion of TCC's pension prepayment asset capitalized to CWIP.

16. Inclusion in rate base of TCC's approved pension prepayment asset and offsetting accumulated deferred income taxes comports with GAAP and PURA § 36.065.

17. No modification would be proper to the rate base treatment or to the 15-year amortization to cost of service of the debt restructuring costs TCC incurred in connection with business separation ordered in Docket Nos. 22352 and 28840.

18. The return on equity and overall return authorized in this proceeding are consistent with the requirements of PURA §§ 36.051 and 36.052.

19. PURA § 39.302(4) allows "the costs of issuing, supporting, and servicing transition bonds and any costs of retiring and refunding the electric utility's debt and equity securities in connection with the issuance of transition bonds" to be included in qualified up-front costs of securitization. Costs in the amount of $1,669,612 that TCC incurred in issuing Matagorda Navigation District No. 1 Pollution Control Bonds Series 2005 and B in 2005 were not incurred in "retiring and refunding . . . [TCC's] debt and equity securities in connection with the issuance of transition bonds," which occurred in late 2006.

20. The costs in the amount of $1,669,612 initially incurred in issuing Matagorda Navigation District No. 1 Pollution Control Bonds Series 2005 and B in 2005 are properly included in TCC's cost of debt calculation. P.U.C. SUBST. R. 25.231(c)(1)(C)(i).

21. TCC's decisions to retire and refund debt using the proceeds of the securitization were prudent under the prudence standard articulated in *Application of Gulf States Utilities Company to Change Rates*, Docket No. 7195, 14 P.U.C. Bull. 1943, 1969-1970, 2429 (CoL 14) (May 16, 1998).

22. For ratemaking purposes, P.U.C. SUBST. R. 25.231(c)(1)(C)(i) requires the cost of debt to be "the actual cost of debt at the time of issuance, plus adjustments for premiums, discounts, and refinancing and issuance costs."

23. The affiliate expenses included in TCC's rates are consistent with the requirements of PURA § 36.058.

24. PURA § 36.065(a) authorizes an unbundled transmission and distribution utility to include in rates the "pension and other postemployment benefits" related to the employees of its predecessor's generation function.

25. As used in PURA § 36.065(a), "pension and other postemployment benefits" (OPEB) includes pension costs under SFAS 87, postretirement benefits under SFAS 106, and postemployment benefits under SFAS 112.

26. Pursuant to P.U.C. SUBST. R. 25.231(b)(1)(H), OPEB shall be included in an electric utility's cost of service for ratemaking purposes based on actual payments made.

27. PURA § 36.064 permits a utility to self-insure "potential liability or catastrophic property loss, including windstorm, fire, and explosion losses, that could not have been reasonably anticipated and included under operating and maintenance expenses." The Commission shall approve a self-insurance plan under that section if it finds the coverage in the public interest, the plan, considering all of its costs, is a lower cost alternative to purchasing commercial insurance, and ratepayers receive the benefits of the savings.

28. A catastrophic property damage loss self-insurance program with an annual accrual of $1,300,000 and a target reserve amount of $13 million is in accordance with PURA § 36.064 and P.U.C. SUBST. R. 25.231(b)(1)(G).

29. PURA § 36.060 requires the use of a consolidated tax savings (CTS) adjustment when computing an electric utility's federal income taxes.

30. PURA §§ 36.061 and 36.062 and P.U.C. SUBST. R. 25.231(b)(2)(A) disallow recovery of legislative advocacy expenses included in professional or trade association dues.

31. PURA § 39.903(g) no longer applies to TCC, which is subject to competition.

32. TCC's proposed level of energy efficiency funding complies with PURA § 39.905(f).

33. P.U.C. SUBST. R. 25.342(f)(1)(D)(ii)(III) requires a utility to "credit all revenues received . . . during the test year after known and measurable adjustments are made to lower the revenue requirement" of the T&D utility. TCC's proposal to make a known and measurable change to its test year margins of $3.3 million and then reduce its revenue requirement by the adjusted margin of $789,714 complies with this requirement.

34. TCC's proposed rate design and cost allocation are consistent with the requirements of PURA §§ 36.003 and 36.004.

35. Termination of the rider credits associated with the Commission's order in Docket No. 19265, contemporaneous with implementation of bonded rates in this proceeding, is consistent with the provisions of PURA § 36.110 and with the express language of the Integrated Stipulation and Agreement approved by the Commission in Docket No. 19265.

III. Ordering Paragraphs

The proposal for decision prepared by the SOAH ALJs is adopted to the extent consistent with this Order.

1. TCC's application is granted to the extent provided in this Order.

2. All issues relating to the recovery of Cities' and TCC's rate case expenses are severed from this proceeding and consolidated with Proceeding to Consider Rate

Case Expenses Severed from Docket No. 33310 (*Application of AEP Texas North company for Authority to Change Rates*, Docket No. 34301 (pending)).

3. TCC shall file tariff sheets consistent with this Order no later than 20 days after receipt of this Order. The compliance tariff, and all filings related to it, shall be filed in Tariff Control Number 35093, and shall be styled: *Compliance Tariff of AEP Texas Central Company Pursuant to Final Order in P.U.C. Docket No. 33309*, (*Application of AEP Texas Central Company for Authority to Change Rates*). The filing shall include a transmittal letter stating that the tariffs attached are in compliance with the order, giving the docket number, date of the order, a list of tariff sheets filed, and any other necessary information. No later than 10 days after the date of the tariff filings, Commission Staff shall file its comments recommending approval, modification, or rejection of the individual sheets of the tariff proposal. Responses to the Commission Staff's recommendation shall be filed no later than 15 days after the filing of the tariff. The Commission shall by letter approve, modify, or reject each tariff sheet, effective the date of the letter.

4. Pursuant to PURA § 36.110(d) TCC shall (1) refund or credit bills for money collected under the bonded rates put into effect on or after May 30, 2007 in excess of the base rate revenue increase ordered in this docket; and (2) include interest on that money at the current approved Commission approved interest rates. TCC shall file in Tariff Control Number 35093 calculations supporting the amounts and a tariff to implement the refund or credit.

5. The tariff sheets shall be deemed approved and shall be become effective upon the expiration of 20 days from the date of filing, in the absence of written notification of modification or rejection by the Commission. If any sheets are modified or rejected, TCC shall file proposed revisions of those sheets in accordance with the Commission's letter within 10 days of the date of that letter, and the review procedure set out above shall apply to the revised sheets.

6. Copies of all tariff-related filings shall be served on all parties of record.

7. All other motions, requests for entry of specific findings of fact and conclusions of law, and any other requests for general or specific relief, if not expressly granted, are denied.

SIGNED AT AUSTIN, TEXAS the 4th day of ~~February~~ March 2008.

PUBLIC UTILITY COMMISSION OF TEXAS

BARRY T. SMITHERMAN, CHAIRMAN

JULIE PARSLEY, COMMISSIONER

PAUL HUDSON, COMMISSIONER

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Final Order
Schedule I
Revenue Requirement

DOCKET NUMBER 33309
COMPANY NAME AEP TEXAS CENTRAL COMPANY
TEST YEAR END 30-Jun-06

	Test Year Total	Company Adjustments To Test Year	Company Adjusted Test Year Total Electric	Recommended Adjust. To Co. Request	Final Order Adjusted Total Electric
	(a)	(b)	(c)	(d)	(e)=(c)+(d)
REVENUE REQUIREMENT					
Operations & Maintenance	296,033,365	(36,179,627)	259,853,738	(14,328,513)	245,525,225
Depreciation & Amortization Expense	98,502,951	(20,891,707)	77,611,244	(2,781,840)	74,829,404
Taxes Other Than Income Taxes	80,617,871	(277,099)	80,340,772	(4,416,323)	75,924,449
Federal Income Tax	58,197,809	(21,306,639)	35,036,739	(8,095,772)	26,940,967
Return on Invested Capital	206,700,718	(77,415,253)	129,285,465	(10,797,736)	117,487,730
TOTAL REVENUE REQUIREMENT	739,052,714	(156,070,225)	581,127,968	(40,420,183)	540,707,774
MINUS: OTHER REVENUE	(38,539,566)		(38,539,566)		(38,539,566)
TOTAL ADJUSTED REVENUE REQUIREMENT	700,513,148	(156,070,225)	542,588,392	(40,420,183)	502,168,208

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DOCKET NUMBER 33309
COMPANY NAME AEP TEXAS CENTRAL COMPANY
TEST YEAR END 30-Jun-08

		Test Year Total	Company Adjustments To Test Year	Company Adjusted Test Year Total Electric	Recommended Adjust. To Co. Request	Final order Adjusted Total Electric
		(a)	(b)	(c)	(d)	(e)=(c)+(d)
TOTAL O & M EXPENSE (Operations & Maintenance + Admin & General)						
Operations & Maintenance:						
System Control & Load Dispatch	556	204,785	(10,780)	193,[illegible]	(3,[illegible])	182,072
Other Expenses	557	(602)	0	(602)	0	(602)
Transmission Ops Supr & Engr	560	1,406,140	(108,913)	1,297,227	(55,702)	1,241,525
Transmission Load Dispatching	561	1,735,071	(131,743)	1,603,[illegible]	(39,[illegible])	1,564,[illegible]
Transmission Station Expenses	562	897,851	670	898,521	(13,[illegible])	884,[illegible]
Trans OH Line Expense	563	730,[illegible]	575	730,411	(10,[illegible])	720,072
Underground Line Expenses	564	45,361,[illegible]	7,272,340	52,633,[illegible]	0	52,633,[illegible]
Transmission of Elect. by Others	565	1,565,205	(367,773)	1,197,430	(810,573)	386,857
Misc. Transmission Expenses	566	2,380,657	(116,269)	2,264,[illegible]	(312,430)	1,952,410
Rents	567	211,760	126,480	338,240	0	338,240
Transmission Maint Supr & Engr	568	122,275	(2,075)	120,160	(4,084)	116,132
Transmission Maint of Structures	569	73,620	79	73,[illegible]	(1,430)	72,175
Transmission Maint Station Equip	570	4,172,250	(350,722)	3,821,537	(87,834)	3,733,750
Transmission Maint OH Line Exp	571	3,600,273	(338)	3,599,[illegible]	(21,108)	3,578,[illegible]
Underground Line Expenses	572	0	0	0	0	0
Maint Misc Transmission Plant	573	(19)	(95)	(114)	0	(114)
Distribution Ops Supr & Engr	580	5,301,382	(294,745)	5,006,617	(407,547)	4,599,070
Distribution Load Dispatching	581	3,564,540	(413,[illegible])	3,146,[illegible]	(106,[illegible])	3,039,[illegible]
Distribution Station Expenses	582	[illegible]	(20,[illegible])	943,202	(20,011)	922,4[illegible]
Distribution OH Line Expenses	583	4,087,374	157,474	4,244,[illegible]	(84,418)	4,160,430
Underground Line Expenses	584	1,214,820	27,[illegible]	1,241,[illegible]	(20,[illegible])	1,220,[illegible]
Street Lighting & Signal Sys	585	62,292	3,027	65,319	(1,7[illegible])	63,[illegible]
Meter Expenses	586	1,616,380	83,165	1,[illegible]	(157,[illegible])	1,542,[illegible]
Customer Installations	587	738,347	13,[illegible]	751,[illegible]	(19,977)	731,972
Miscellaneous Distribution Exp	588	14,591,405	92,[illegible]	14,651,7[illegible]	(415,[illegible])	14,236,[illegible]
Rents	589	2,013,465	(641,873)	1,371,[illegible]	0	1,371,[illegible]
Distribution Maint Supr & Engr	590	251,[illegible]	(1,434)	250,[illegible]	(3,173)	247,[illegible]
Distribution Maint of Structures	591	[illegible]	[illegible]	[illegible]	(1,[illegible])	[illegible]
Distribution Maint Station Equip	592	4,277,843	(40,010)	4,237,[illegible]	(63,[illegible])	4,164,[illegible]
Distribution Maint OH lines	593	14,000,001	238,730	14,248,730	(148,[illegible])	14,099,[illegible]
Underground Line Expenses	594	735,[illegible]	24,514	7[illegible]	(14,[illegible])	745,[illegible]
Dist Maint Line Trsf, Rglators	595	3,321,[illegible]	135,322	3,457,144	(61,130)	3,396,[illegible]
Maint-Street Light & Signal Sys	596	3[illegible]	12,122	395,575	(15,[illegible])	380,[illegible]
Maintenance of Meters	597	421,[illegible]	25,[illegible]	447,[illegible]	(1,[illegible])	445,147
Maint of Misc Dist Plant	598	175,[illegible]	(2,257)	173,[illegible]	0	173,[illegible]
Supervision - Customer Accts	901	2,210,[illegible]	(108,[illegible])	2,[illegible]	(342,[illegible])	1,720,216
Meter Reading Exp	902	8,411,[illegible]	316,510	8,727,145	(205,101)	8,523,[illegible]
Customer Records & Collection	903	15,[illegible]	(1,7[illegible])	13,[illegible]	(614,7[illegible])	12,679,[illegible]
Uncollectible Accounts	904	242,[illegible]	388,791	631,[illegible]	(495,[illegible])	136,346
Misc Customer Accounts Exp	905	61,323	(6,[illegible])	52,518	(17,[illegible])	35,117
Customer Service Supervision	907	5,524,484	2,474,345	8,[illegible]	(822,[illegible])	7,176,974
Customer Assistance	908	1,745,[illegible]	103,248	1,848,[illegible]	(71,302)	1,776,536
Information & Instr Advertising	909	610,[illegible]	0	610,[illegible]	(37)	610,[illegible]
Misc Customer Svc & Inform Exp	910	118,[illegible]	117	118,791	(329)	118,462
Demonstrating & Selling Exp	911	0	0	0	0	0
Advertising Expense	912	165,[illegible]	(165,[illegible])	0	0	0
Miscellaneous Sales Expense	913	0	0	0	0	0
TOTAL Operations & Maintenance		194,[illegible]	[illegible]	201,7[illegible]	(5,590,3[illegible])	196,[illegible]
Adjusted Administrative & General:						
Admin & General Salaries	920	22,[illegible],373	(4,[illegible])	18,757,[illegible]	(5,381,431)	13,3[illegible],107
Office Supplies & Exp	921	2,217,877	(758,[illegible])	1,459,160	(161,011)	1,298,279
Admin Expenses Transferred	922	(5,340,3[illegible])	[illegible]	(5,286,7[illegible])	(41,[illegible])	(5,327,[illegible])
Outside Services	923	17,100,132	(1,[illegible])	16,244,[illegible]	(529,[illegible])	14,714,216
Property Insurance	924	[illegible]	3,[illegible]	4,075,723	(2,[illegible])	1,460,721
Injuries & Damages	925	2,470,181	(138,[illegible])	2,331,3[illegible]	0	2,331,3[illegible]
Employee Pensions & Benefits	926	5,705,[illegible]	3,542,424	9,247,[illegible]	550,[illegible]	9,798,[illegible]
Regulatory Commission Exp	928	5,834,[illegible]	(3,[illegible])	1,758,813	(47,[illegible])	1,711,3[illegible]
Miscellaneous General Exp	930	42,2[illegible]	(39,[illegible])	2,955,129	(488,[illegible])	2,466,[illegible]
Rents	931	2,336,[illegible]	(46)	2,336,[illegible]	(4,3[illegible])	2,332,2[illegible]
Maint of General Plant	935	5,[illegible]	116,129	5,2[illegible]	(69,[illegible])	5,138,4[illegible]
TOTAL Administrative & General		101,138,[illegible]	(43,[illegible])	58,[illegible]	(8,738,[illegible])	49,3[illegible]
TOTAL O & M EXPENSE		296,[illegible]	(38,170,[illegible])	258,353,7[illegible]	(14,328,[illegible])	245,[illegible]

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Final Order
Schedule III
Invested Capital

DOCKET NUMBER 33309
COMPANY NAME AEP TEXAS CENTRAL COMPANY
TEST YEAR END 30-Jun-06

	Test Year Total	Company Adjustments To Test Year	Company Adjusted Test Year Total Electric	Recommended Adjust. To Co. Request	Final Order Adjusted Total Electric
	(a)	(b)	(c)	(d)	(e)=(c)+(d)
INVESTED CAPITAL					
Plant in Service	2,658,106,172	6,080,094	2,664,186,266	(2,243,242)	2,661,943,024
Accumulated Depreciation	(867,692,603)	613,007	(867,079,596)	0	(867,079,596)
Net Plant in Service	1,790,413,569	6,693,101	1,797,106,670	(2,243,242)	1,794,863,428
Construction Work In Progress	0	0	0		0
Plant Held for Future Use	0	0	0		0
Working Cash Allowance	6,605,496	0	6,605,496	(8,942,063)	(2,336,568)
Materials and Supplies	21,796,562	(6,015,953)	15,780,609	0	15,780,609
Prepayments	114,759,964	0	114,759,964	(22,799,000)	91,960,964
Regulatory Assets	1,686,675,388	(1,665,490,091)	21,185,297	0	21,185,297
SFAS 109 Reg. Liability	(30,411,436)	0	(30,411,436)		(30,411,436)
Deferred Federal Income Taxes	(1,022,891,875)	698,972,101	(323,919,774)	0	(323,919,774)
Customer Advances for Construction	0		0	0	0
Customer Deposits	686,650	0	686,650	0	686,650
Asset Retirement obligations	(1,201,634)	9,402	(1,192,232)	0	(1,192,232)
Investment Tax Credits	(116,089)	0	(116,089)	0	(116,089)
TOTAL INVESTED CAPITAL	2,566,318,615	(965,831,440)	1,600,487,375	(33,984,305)	1,566,503,070
RATE OF RETURN	8.0154%		8.0154%		7.5000%
RETURN ON INVESTED CAPITAL	205,700,716		128,285,465		117,487,730

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Final Order
Schedule IV
Taxes Other Than FIT

DOCKET NUMBER 33309
COMPANY NAME AEP TEXAS CENTRAL COMPANY
TEST YEAR END 30-Jun-08

	Test Year Total	Company Adjustments To Test Year	Company Adjusted Test Year Total Electric	Recommended Adjust. To Co. Request	Final Order Adjusted Total Electric
	(a)	(b)	(c)	(d)	(e)=(c)+(d)
TAXES OTHER THAN FIT					
Ad Valorem Taxes	30,985,808	953,313	31,939,121	(4,123,063)	27,816,058
Payroll Taxes	3,302,663	157,087	3,459,750	0	3,459,750
Sales and Use	(557,545)	1,042,850	485,305		485,305
Federal Excise\ St. Lic.	1,009	0	1,009		1,009
Municipal Franchise Taxes	41,044,325	(398,142)	40,646,183		40,646,183
Franchise Tax	5,841,621	(5,841,621)	0		
Gross Margin Taxes	0	3,809,404	3,809,404	(293,260)	3,516,144
TOTAL TAXES OTHER THAN INCOME TAXES	80,617,871	(277,099)	80,340,772	(4,416,323)	75,924,449

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DOCKET NUMBER 33309
COMPANY NAME AEP TEXAS CENTRAL COMPANY
TEST YEAR END 30-Jun-06

Final Order
Schedule IV
Taxes Other Than FIT

TAXES OTHER THAN FIT	Test Year Total (a)	Company Adjustments To Test Year (b)	Company Adjusted Test Year Total Electric (c)	Recommended Adjust. To Co. Request (d)	Final Order Adjusted Total Electric (e)=(c)+(d)
Ad Valorem Taxes	30,985,808	953,313	31,939,121	(4,123,063)	27,816,058
Payroll Taxes	3,302,653	157,097	3,459,750	0	3,459,750
Sales and Use	(557,545)	1,042,850	485,305		485,305
Federal Excise\ St. Lic.	1,009	0	1,009		1,009
Municipal Franchise Taxes	41,044,325	(398,142)	40,646,183		40,646,183
Franchise Tax	5,841,621	(5,841,621)	0		
Gross Margin Taxes	0	3,809,404	3,809,404	(293,260)	3,516,144
TOTAL TAXES OTHER THAN INCOME TAXES	80,617,871	(277,099)	80,340,772	(4,416,323)	75,924,449

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PUBLIC UTILITY COMMISSION OF TEXAS
AEP TEXAS CENTRAL COMPANY
II-B-1 RATE BASE ACCOUNTS - PLANT
TEST YEAR ENDING 6/30/2006
DOCKET NO. 33309
TRANSMISSION MODEL

Final Order Schedule II-B-1

Account Number	Description	Reference Schedule	1 TRAN Function	3 Total TX Company	6 Residential	7 Secondary <=10 kW	8 Secondary > 10 kW IDR	9 Secondary > 10 kW Non-IDR	10 Primary IDR	11 Primary Non-IDR	12 Transmission	15 Total
Intangible Plant-Gross		II-B-1										
A301	Organization		-	-	-	-	-	-	-	-	-	-
A302	Franchise & Consents		-	-	-	-	-	-	-	-	-	-
A303	Miscellaneous Intangible Plant		5,201,385	5,201,385	2,455,499	89,402	105,218	1,520,096	507,950	54,493	468,726	5,201,385
	Subtotal		**5,201,385**	**5,201,385**	**2,455,499**	**89,402**	**105,218**	**1,520,096**	**507,950**	**54,493**	**468,726**	**5,201,385**
Transmission Plant-Gross		II-B-1										
A349	Land Owned in Fee		-	-	-	-	-	-	-	-	-	-
A350	Land and Land Rights		41,993,373	41,993,373	19,824,471	721,791	849,481	12,272,493	4,100,936	439,946	3,784,256	41,993,373
A352	Structures and Improvements		6,642,503	6,642,503	3,135,831	114,173	134,371	1,941,260	648,685	69,591	598,593	6,642,503
A353	Station Equipment		405,013,505	405,013,505	191,201,084	6,961,456	8,192,991	118,364,520	39,552,298	4,243,144	36,498,012	405,013,505
A354	Towers and Fixtures		36,367,901	36,367,901	17,168,766	625,099	735,684	10,628,458	3,551,571	381,010	3,277,313	36,367,901
A355	Poles and Fixtures		185,135,611	185,135,611	87,399,874	3,182,149	3,745,096	54,105,573	18,079,740	1,939,582	16,683,596	185,135,611
A356	O H Conductors & Devices		188,397,542	188,397,542	88,939,785	3,238,216	3,811,081	55,058,867	18,398,290	1,973,756	16,977,547	188,397,542
A357	Underground Conduit		530,085	530,085	250,246	9,111	10,723	154,916	51,766	5,553	47,769	530,085
A358	Underground Conductors		15,555,333	15,555,333	7,343,450	267,368	314,668	4,546,020	1,519,083	162,966	1,401,777	15,555,333
A359	Roads and Trails		404,248	404,248	190,840	6,948	8,178	118,141	39,478	4,235	36,429	404,248
	Subtotal		**880,040,401**	**880,040,101**	**415,454,347**	**15,126,311**	**17,802,272**	**257,190,248**	**85,941,847**	**9,219,784**	**79,305,292**	**880,040,101**
Distribution Plant-Gross		II-B-1										
A360	Land and Land Rights		159,317	159,317	75,211	2,738	3,223	46,560	15,558	1,669	14,357	159,317
A361	Structures and Improvements		1,414,094	1,414,094	667,574	24,306	28,606	413,267	138,096	14,815	127,432	1,414,094
A362	Station Equipment		31,218,251	31,218,251	14,737,690	536,586	631,512	9,123,482	3,048,673	327,060	2,813,350	31,218,251
A363	Storage Battery Equipment		-	-	-	-	-	-	-	-	-	-
A364P	Poles,Towers & Fixtures-Primary		-	-	-	-	-	-	-	-	-	-
A365P	O H Conductors & Devices-Primary		-	-	-	-	-	-	-	-	-	-
A366P	Underground Conduits-Primary		-	-	-	-	-	-	-	-	-	-
A367P	U G Conductors & Devices-Primary		-	-	-	-	-	-	-	-	-	-
A368P	Line Transformers-Primary		-	-	-	-	-	-	-	-	-	-
A369	Services		-	-	-	-	-	-	-	-	-	-
A370	Meters		-	-	-	-	-	-	-	-	-	-
A371	Install on Customer Prem		-	-	-	-	-	-	-	-	-	-
A372	Leased Prop on Cust Premises		-	-	-	-	-	-	-	-	-	-
A373	Street Lights		-	-	-	-	-	-	-	-	-	-
A374	Land Owned in Fee		-	-	-	-	-	-	-	-	-	-
	Subtotal		**32,791,662**	**32,791,662**	**15,400,475**	**563,630**	**663,340**	**9,583,308**	**3,202,327**	**343,543**	**2,955,036**	**32,791,662**
TOTAL INT, TRAN, DIST PLANT-GROSS		II-B-1	**918,033,148**	**918,833,148**	**433,390,321**	**15,779,344**	**18,570,831**	**268,293,653**	**89,652,124**	**9,617,820**	**82,729,856**	**918,833,148**
TOTAL TRAN, DIST PLANT-GROSS		II-B-1	**912,831,763**	**912,831,763**	**430,934,822**	**15,689,942**	**18,466,612**	**266,773,556**	**89,144,174**	**9,563,327**	**82,260,330**	**912,831,763**

Finding of Fact No. 23

PUBLIC UTILITY COMMISSION OF TEXAS
AEP TEXAS CENTRAL COMPANY
II-B-5 RATE BASE ACCOUNTS DEPRECIATION - PLANT
TEST YEAR ENDING 6/30/2006
DOCKET NO. 33309
TRANSMISSION MODEL

Final Order - Schedule II-B-5

			4	5	6	7	8	9	10	11	12	15
Account Number	Description	Reference Schedule	TRAN Function	Total TX Company	Residential	Secondary <=10 kW	Secondary > 10 kW IDR	Secondary > 10 kW Non IDR	Primary IDR	Primary Non IDR	Transmission	Total
	Intangible Plant											
	Accumulated Depreciation	II-B-5	xxxxxx									
A301	Organization		-	-	-	-	-	-	-	-	-	-
A302	Franchise & Consents		-	-	-	-	-	-	-	-	-	-
A303	Miscellaneous Intangible Plant		2,069,768	2,069,768	977,108	35,576	41,869	604,886	202,127	21,684	186,518	2,069,768
	Subtotal		**2,069,768**	**2,069,768**	**977,108**	**35,576**	**41,869**	**604,886**	**202,127**	**21,684**	**186,518**	**2,069,768**
	Transmission Plant											
	Accumulated Depreciation	II-B-5										
A349	Land Owned in Fee		-	-	-	-	-	-	-	-	-	-
A350	Land and Land Rights		16,104,854	16,104,854	7,602,871	276,814	325,784	4,706,617	1,572,748	168,723	1,451,298	16,104,854
A352	Structures and Improvements		2,911,284	2,911,284	1,374,375	50,040	58,892	850,818	284,306	30,500	262,352	2,911,284
A353	Station Equipment		85,814,006	85,814,006	40,511,565	1,474,989	1,735,926	25,079,000	8,380,316	899,035	7,733,176	85,814,006
A354	Towers and Fixtures		19,870,836	19,870,836	9,380,738	341,544	401,966	5,807,219	1,940,521	208,178	1,790,671	19,870,836
A355	Poles and Fixtures		65,054,891	65,054,891	30,711,484	1,118,177	1,315,991	19,012,183	6,353,049	681,551	5,862,457	65,054,891
A356	O.H. Conductors & Devices		68,055,969	68,055,969	32,128,250	1,169,760	1,376,700	19,889,243	6,646,124	712,992	6,132,901	68,055,969
A357	Underground Conduit		452,796	452,796	213,759	7,783	9,160	132,329	44,219	4,744	40,804	452,796
A358	Underground Conductors		6,087,271	6,087,271	2,873,714	104,629	123,139	1,778,995	594,463	63,774	548,558	6,087,271
A359	Roads and Trails		188,312	188,312	88,899	3,237	3,809	55,034	18,390	1,973	16,970	188,312
	Subtotal		**264,540,220**	**264,540,220**	**124,885,655**	**4,546,972**	**5,351,366**	**77,311,437**	**25,834,135**	**2,771,469**	**23,839,186**	**264,540,220**
	Distribution Plant											
	Accumulated Depreciation	II-B-5										
A360	Land and Land Rights		12,059	12,059	5,693	207	244	3,524	1,178	126	1,087	12,059
A361	Structures and Improvements		556,342	556,342	262,641	9,563	11,254	162,590	54,331	5,829	50,135	556,342
A362	Station Equipment		4,771,739	4,771,739	2,252,670	82,018	96,527	1,394,533	465,992	49,991	430,008	4,771,739
A363	Storage Battery Equipment		-	-	-	-	-	-	-	-	-	
A364P	Poles Towers & Fixtures-Primary		-		-	-	-	-		-	-	-
A365P	O.H. Conductors & Devices Primary		-	-	-	-	-	-	-	-	-	-
A366P	Underground Conduits-Primary		-		-	-	-	-	-	-	-	-
A367P	U.G. Conductors & Devices Primary		-	-	-	-	-		-	-	-	-
A368P	Line Transformers Primary		-		-	-	-		-	-	-	-
A369	Services				-	-	-	-	-	-	-	-
A370	Meters		-		-	-	-	-	-	-	-	-
A371	Install. on Customer Prem.		-	-	-	-	-	-	-	-	-	-
A372	Leased Prop. on Cust. Premises			-	-	-	-	-	-	-	-	-
A373	Street Lights		-	-	-	-	-	-	-	-	-	-
	Subtotal		**5,340,139**	**5,340,139**	**2,321,003**	**91,787**	**108,025**	**1,560,647**	**531,504**	**55,946**	**481,230**	**5,340,139**
	TOTAL INT, TRAN, DIST PLANT-ACCUM DEP.	II-B-5	**271,950,128**	**271,950,128**	**128,383,766**	**4,674,330**	**5,501,201**	**79,476,970**	**26,597,783**	**2,849,089**	**24,506,933**	**271,950,128**
	TOTAL TRAN, DIST PLANT-ACCUM DEP.	II-B-5	**269,880,360**	**269,880,360**	**127,406,658**	**4,638,759**	**5,459,392**	**78,872,084**	**26,365,636**	**2,827,415**	**24,320,416**	**269,880,360**
	TOTAL INT, TRAN, DIST PLANT-NET	II-B-1 - II-B-5	**646,083,020**	**646,083,020**	**388,006,005**	**11,145,080**	**13,089,570**	**188,016,482**	**63,004,361**	**6,768,721**	**98,222,122**	**646,083,020**
	TOTAL TRAN, DIST PLANT-NET	II-B-1 - II-B-5	**642,951,403**	**642,951,403**	**383,528,163**	**11,461,182**	**13,006,221**	**187,981,473**	**62,788,530**	**6,735,912**	**97,930,919**	**642,951,403**

Finding of Fact No. 23

PUBLIC UTILITY COMMISSION OF TEXAS
AEP TEXAS CENTRAL COMPANY
II-B-5 RATE BASE ACCOUNTS DEPRECIATION - PLANT
TEST YEAR ENDING 6/30/2006
DOCKET NO. 33309
DISTRIBUTION MODEL

Final Order Schedule II-B-5

			1	3	6	7	8	9	10	11	12	13	15
Account Number	Description	Reference Schedule	DIST Function	Total TX Company	Residential	Secondary <=10 kW	Secondary > 10 kW IDR	Secondary > 10 kW Non-IDR	Primary IDR	Primary Non-IDR	Transmission	Lighting	Total
Intangible Plant													
Accumulated Depreciation		II-B-5											
A301	Organization		-	-	-	-	-	-	-	-	-	-	-
A302	Franchise & Consents		-	-	-	-	-	-	-	-		-	-
A303	Miscellaneous Intangible Plant		22,913,695	22,913,695	12,073,157	527,690	562,059	7,128,483	1,387,629	141,129	630	1,092,927	22,913,695
	Subtotal		22,913,695	22,913,695	12,073,157	527,690	562,059	7,128,483	1,387,629	141,129	630	1,092,927	22,913,695
Transmission Plant													
Accumulated Depreciation		II-B-5											
A349	Land Owned in Fee		-		-	-	-	-	-	-	-	-	-
A350	Land and Land Rights		298,442	298,442	152,558	5,975	7,318	91,822	32,490	3,304	-	4,975	298,442
A352	Structures and Improvements		321,557	321,557	164,373	6,438	7,885	98,933	35,006	3,560	-	5,360	321,557
A353	Station Equipment		3,756,030	3,756,030	1,920,007	75,203	92,104	1,155,617	408,901	41,586	-	62,612	3,756,030
A354	Towers and Fixtures		-	-	-	-	-	-	-	-	-	-	-
A355	Poles and Fixtures		-	-	-	-	-	-	-	-	-	-	-
A356	O.H. Conductors & Devices		-	-	-	-	-	-	-	-	-	-	-
A357	Underground Conduit			-	-	-	-	-	-	-	-	-	-
A358	Underground Conductors		-	-	-	-	-	-	-	-	-	-	-
A359	Roads and Trails		-	-	-	-	-	-	-	-		-	-
	Subtotal		4,376,029	4,376,029	2,236,937	87,617	107,307	1,346,372	476,398	48,451	-	72,947	4,376,029
Distribution Plant													
Accumulated Depreciation		II-B-5											
A360	Land and Land Rights		291,185	291,185	148,848	5,830	7,140	89,589	31,700	3,224	-	4,854	291,185
A361	Structures and Improvements		1,897,766	1,897,766	970,100	37,997	46,536	583,885	206,601	21,012	-	31,635	1,897,766
A362	Station Equipment		16,696,690	16,696,690	8,535,000	334,302	409,429	5,137,066	1,817,690	184,864	-	278,329	16,696,690
A363	Storage Battery Equipment		-	-	-	-	-	-	-	-	-	-	-
A364P	Poles Towers & Fixtures Primary		126,875,564	126,875,564	68,229,092	2,672,421	3,272,987	41,065,840	8,541,555	868,699	-	2,324,970	126,875,564
A365P	O.H. Conductors & Devices Primary		99,678,202	99,678,202	52,992,256	2,075,619	2,542,068	31,895,067	7,665,498	779,602	-	1,728,093	99,678,202
A366P	Underground Conduits-Primary		9,005,922	9,005,922	4,714,945	184,677	226,179	2,837,839	806,504	82,024	-	153,756	9,005,922
A367P	U.G. Conductors & Devices-Primary		32,495,937	32,495,937	17,012,867	666,366	816,117	10,239,733	2,910,096	295,964	-	554,794	32,495,937
A368P	Line Transformers Primary		112,431,981	112,431,981	64,721,985	2,535,053	3,104,749	38,954,976	911,876	92,740	-	2,110,602	112,431,981
A369	Services		44,859,564	44,859,564	31,770,838	6,047,264	27,306	7,014,157	-	-	-	-	44,859,564
A370	Meters		-	-	-	-	-	-	-	-	-	-	-
A371	Install. on Customer Prem.		26,924,639	26,924,639	-	-	-	-	-		-	26,924,639	26,924,639
A372	Leased Prop. on Cust. Premises		-	-	-	-	-	-	-	-	-		-
A373	Street Lights		16,953,260	16,953,260	-	-	-	-	-	-	-	16,953,260	16,953,260
	Subtotal		488,110,711	488,110,711	249,095,939	14,559,529	10,452,510	137,818,151	22,891,530	2,328,128	-	50,964,933	488,110,711
TOTAL INT, TRAN, DIST PLANT-ACCUM DEP.		II-B-5	515,400,435	515,400,435	263,406,833	15,174,837	11,131,876	146,393,866	24,758,346	2,517,709	630	52,130,868	515,400,435
TOTAL TRAN, DIST PLANT-ACCUM DEP.		II-B-5	492,486,740	492,486,740	251,332,077	14,647,146	10,559,817	139,164,523	23,367,917	2,376,979	-	51,037,880	492,486,740
TOTAL INT, TRAN, DIST PLANT-NET		II-B-1 - II-B-5	967,700,188	967,700,188	503,569,374	27,808,406	21,861,398	284,512,567	53,927,110	5,484,530	381	71,346,183	967,700,188
TOTAL TRAN, DIST PLANT-NET		II-B-1 - II-B-5	953,628,481	953,628,481	496,155,834	26,764,632	21,516,186	280,144,839	53,074,942	5,397,063	-	70,574,997	953,628,481

Finding of Fact No. 24

PUBLIC UTILITY COMMISSION OF TEXAS
AEP TEXAS CENTRAL COMPANY
II-B-1 RATE BASE ACCOUNTS - PLANT
TEST YEAR ENDING 6/30/2006
DOCKET NO. 33309
DISTRIBUTION MODEL

Final Order Schedule II-B-1

			1	5	6	7	8	9	10	11	12	13	15
Account Number	Description	Reference Schedule	DIST Function	Total TX Company	Residential	Secondary <=10 kW	Secondary > 10 kW IDR	Secondary > 10 kW Non-IDR	Primary IDR	Primary Non-IDR	Transmission	Lighting	Total
Intangible Plant-Gross		II-B-1											
A301	Organization		-	-	-	-	-	-	-	-	-	-	-
A302	Franchise & Consents		-	-	-	-	-	-	-	-	-	-	-
A303	Miscellaneous Intangible Plant		36,985,402	36,985,402	19,487,497	851,755	907,229	11,506,211	2,239,796	227,800	1,001	1,764,113	36,985,402
	Subtotal		**36,985,402**	**36,985,402**	**19,487,497**	**851,755**	**907,229**	**11,506,211**	**2,239,796**	**227,800**	**1,001**	**1,764,113**	**36,985,402**
Transmission Plant-Gross		II-B-1											
A349	Land Owned in Fee		-	-	-	-	-	-	-	-	-	-	-
A350	Land and Land Rights		771,778	771,778	394,517	15,453	18,925	237,453	84,020	8,545		12,865	771,778
A352	Structures and Improvements		733,678	733,678	375,041	14,690	17,991	225,730	79,872	8,123	-	13,230	733,678
A353	Station Equipment		17,507,739	17,507,739	8,949,601	350,541	429,317	5,386,601	1,905,985	193,844	-	291,649	17,507,739
A354	Towers and Fixtures		-	-	-	-	-	-	-	-	-	-	-
A355	Poles and Fixtures		-	-	-	-	-	-	-	-	-	-	-
A356	O H Conductors & Devices		-	-	-	-	-	-	-	-	-	-	-
A357	Underground Conduit		-	-	-	-	-	-	-	-	-		-
A358	Underground Conductors		-	-	-	-	-	-	-	-	-	-	-
A359	Roads and Trails		-	-	-	-	-	-	-	-	-	-	-
	Subtotal		**19,013,195**	**19,013,195**	**9,719,160**	**380,683**	**466,233**	**5,849,704**	**2,069,877**	**210,512**	-	**316,945**	**19,013,195**
Distribution Plant-Gross		II-B-1											
A360	Land and Land Rights		3,847,068	3,847,068	1,960,543	77,026	94,336	1,183,626	418,812	42,594	-	64,130	3,847,068
A361	Structures and Improvements		4,821,688	4,821,688	2,465,773	96,580	118,284	1,484,103	525,132	53,407	-	80,410	4,821,688
A362	Station Equipment		109,235,123	109,235,123	55,838,781	2,187,113	2,678,617	33,608,339	11,891,915	1,209,439	-	1,820,919	109,235,123
A363	Storage Battery Equipment		-	-	-	-	-	-	-	-	-		-
A364P	Poles,Towers & Fixtures-Primary		349,261,801	215,983,498	110,406,387	4,324,436	5,296,255	66,451,581	23,513,109	2,391,346	-	3,600,384	215,983,498
				133,278,303	77,413,984	3,032,178	3,713,591	46,594,058	-	-	-	2,524,492	133,278,303
A365P	O.H Conductors & Devices-Primary		370,675,916	191,205,467	97,740,360	3,828,329	4,688,639	58,828,131	20,815,642	2,117,006	-	3,187,341	191,205,467
				79,470,449	46,159,982	1,808,010	2,214,320	37,782,847	-	-	-	1,505,290	79,470,449
A366P	Underground Conduits-Primary		27,676,770	22,766,911	11,637,984	455,841	558,280	7,004,609	2,478,527	252,073	-	379,518	22,766,911
				4,909,859	2,851,865	111,703	136,806	1,716,485	-	-	-	93,000	4,909,859
A367P	U G. Conductors & Devices-Primary		136,209,104	112,045,609	57,275,445	2,343,385	2,747,534	34,473,040	12,197,879	1,240,557	-	1,867,769	112,045,609
				24,163,495	14,035,236	549,737	673,278	8,447,551	-	-	-	457,693	24,163,495
A368P	Line Transformers-Primary		312,185,029	23,257,785	11,888,908	465,669	570,317	7,155,716	2,531,966	257,508	-	387,701	23,257,785
				288,927,244	167,821,832	6,573,504	8,050,505	101,008,884	-	-	-	5,472,718	288,927,244
A369	Services		113,332,958	113,332,958	80,265,672	15,277,774	68,985	17,720,527	-	-	-	-	113,332,958
A370	Meters		-	-	-	-	-	-	-	-	-	-	-
A371	Install on Customer Prem		51,877,201	51,877,201	-	-	-	-	-	-		51,877,201	51,877,201
A372	Leased Prop on Cust Premises		-	-	-	-	-	-	-	-	-	-	-
A373	Street Lights		47,977,368	47,977,368	-	-	-	-	-	-	-	47,977,368	47,977,368
A374	Land Owned in Fee		-	-	-	-	-	-	-	-	-	-	-
	Subtotal		**1,427,102,826**	**1,427,102,826**	**737,768,750**	**41,031,884**	**31,609,769**	**413,459,577**	**74,372,983**	**7,563,930**	-	**121,295,933**	**1,427,102,826**
TOTAL INT, TRAN, DIST PLANT-GROSS		II-B-1	**1,483,100,623**	**1,483,100,623**	**766,975,407**	**42,263,523**	**32,983,231**	**430,815,573**	**78,682,656**	**8,002,242**	**1,001**	**123,376,992**	**1,483,100,623**
TOTAL TRAN, DIST PLANT-GROSS		II-B-1	**1,446,115,221**	**1,446,115,221**	**747,487,910**	**41,411,768**	**32,076,002**	**419,309,361**	**76,442,860**	**7,774,442**	-	**121,612,877**	**1,446,115,221**

Finding of Fact No. 24

PUBLIC UTILITY COMMISSION OF TEXAS
AEP TEXAS CENTRAL COMPANY
II-B SUMMARY OF RATE BASE
TEST YEAR ENDING 6/30/2006
DOCKET 33309
FUNCTIONAL MODEL

Final Order Schedule II-B

Description	Reference Schedule	1 Test Year Allocation to Texas Company	2 Total TX Commission	3 TRAN	4 DIST	5 MET	6 TDCS	7 Total TX-Retail	Check
Original Cost of Plant	II-B-1	2,487,924,114	2,485,681,269	918,033,148	1,483,100,623	84,311,820	235,679	2,485,681,269	(0)
General Plant	II-B-2	108,570,663	108,570,663	8,764,903	90,645,085	7,092,260	2,068,415	108,570,663	(0)
Communication Equipment	II-B-3	67,691,441	67,691,441	17,487,995	45,303,590	2,224,013	2,675,844	67,691,441	
Total Plant		2,664,186,218	2,661,943,373	944,286,046	1,619,049,298	93,628,092	4,979,938	2,661,943,374	(1)
Minus: Accumulated Depreciation	II-B-5	867,079,596	867,079,596	282,640,729	566,214,259	16,179,961	2,044,648	867,079,597	(0)
NET PLANT IN SERVICE		1,797,106,622	1,794,863,777	661,645,317	1,052,835,039	77,448,131	2,935,290	1,794,863,777	(0)
Other Rate Base Items:									
CWIP	II-B-4	-	-	-	-	-	-	-	-
Cash Working Capital	**II-B-9**	**6,605,495**	**(2,341,171)**	**1,361,010**	**(2,660,226)**	**(478,450)**	**(563,505)**	**(2,341,171)**	-
Prepayments	II-B-10	114,759,984	91,963,333	10,350,237	41,941,367	21,242,307	18,429,421	91,963,333	-
Materials & Supplies	II-B-8	15,780,609	15,780,609	4,629,960	10,510,748	607,532	32,370	15,780,610	(1)
Plant Held for Future Use	II-B-6	-	-	-	-	-	-	-	-
ADIT & FAS 109 Accts.	II-B-7	(324,423,155)	(324,423,155)	(88,437,720)	(209,495,425)	(18,983,148)	(7,506,862)	(324,423,155)	0
Rate Base - Other	II-B-11	(30,527,524)	(30,527,524)	(6,191,333)	(22,939,613)	(1,325,932)	(70,646)	(30,527,524)	-
Regulatory Assets	II-B-12	21,185,297	21,185,297	7,182,508	13,199,212	762,927	40,650	21,185,297	0
Customer Deposits		-	-	-	-	-	-	-	-
Reserve For Insurance		-	-	-	-	-	-	-	-
Subtotal		(196,619,293)	(228,362,611)	(71,105,337)	(169,443,937)	1,825,236	10,361,427	(228,362,610)	(1)
TOTAL RATE BASE		1,600,487,328	1,566,501,166	590,539,979	883,391,102	79,273,367	13,296,717	1,566,501,167	(1)
Rate of Return		8.015%	7.500%	7.500%	7.500%	7.500%	7.500%	7.500%	-
RETURN ON RATE BASE		128,285,461	117,487,587	44,290,498	66,254,333	5,945,503	997,254	117,487,587	(0)

Finding of Fact No. 42

PUC DOCKET NO. 39896
SOAH DOCKET NO. 473-12-2979

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PUBLIC UTILITY COMMISSION
FILING CLERK

APPLICATION OF ENTERGY TEXAS, INC. FOR AUTHORITY TO CHANGE RATES, RECONCILE FUEL COSTS, AND OBTAIN DEFERRED ACCOUNTING TREATMENT	§ § § § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

ORDER

This Order addresses the application of Entergy Texas, Inc. for authority to change rates, reconcile fuel costs, and defer costs for the transition to the Midwest Independent System Operator (MISO). In its application, Entergy requested approval of an increase in annual base-rate revenues of approximately $111.8 million (later lowered to $104.8 million), proposed tariff schedules, including new riders to recover costs related to purchased-power capacity and renewable-energy credit requirements, requested final reconciliation of its fuel costs, and requested waivers to the rate-filing package requirements.

On July 6, 2012, the State Office of Administrative Hearings (SOAH) administrative law judges (ALJs) issued a proposal for decision in which they recommended an overall rate increase for Entergy of $28.3 million resulting in a total revenue requirement of approximately $781 million. The ALJs also recommended approving total fuel costs of approximately $1.3 billion. The ALJs did not recommend approving the renewable-energy credit rider and the Commission earlier removed the purchased-power capacity rider as an issue to be addressed in this docket.[1] On August 8, 2012, the ALJs filed corrections to the proposal for decision based on the exceptions and replies of the parties.[2] Except as discussed in this Order, the Commission adopts the proposal for decision, as corrected, including findings of fact and conclusions of law.

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[1] Supplemental Preliminary Order at 2, 3 (Jan. 19, 2012).

[2] Letter from SOAH judges to PUC (Aug. 8, 2012).

I. Discussion

A. Prepaid Pension Asset Balance

Entergy included in rate base an approximately $56 million item named Unfunded Pension.[3] This amount represents the accumulated difference between the annual pension costs calculated in accordance with the Statement of Financial Accounting Standards (SFAS) No. 87 and the actual contributions made by Entergy to the pension fund—Entergy contributed nearly $56 million more to its pension fund than the minimum required by SFAS No. 87.[4]

In Docket No. 33309, the Commission allowed a pension prepayment asset, excluding the portion of the asset that is capitalized to construction work in progress (CWIP), less accrued deferred federal income taxes (ADFIT) to be included in rate base.[5] For the excluded portion, the Commission allowed the accrual of an allowance for funds used during construction (AFUDC).[6] The ALJs concluded that this approach was sound and should be followed in this case.[7] Thus, the ALJs recommended that the CWIP-related portion of Entergy's prepaid pension asset ($25,311,236) should be excluded from the asset and should accrue AFUDC.[8] However, the ALJs did not address ADFIT.

The Commission agrees that the CWIP-related portion of Entergy's pension asset should be excluded from the asset and that this excluded portion should accrue AFUDC. However, the Commission also finds that the impact of this exclusion on Entergy's ADFIT should be reflected. When items are excluded from rate base, the related ADFIT should also be excluded. The adjusted ADFIT for the prepaid pension asset remaining in Entergy's rate base should be reduced by $8,858,933, the deferred taxes related to the excluded $25 million. The Commission adds new finding of fact 28A to reflect this modification to Entergy's ADFIT.

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[3] Proposal for Decision at 23 (July 6, 2012) (PFD).

[4] PFD at 23-24.

[5] *Application of AEP Texas Central Company for Authority to Change Rates*, Docket No. 33309, Order on Rehearing (March 4, 2008).

[6] *Remand of Docket No. 33309 (Application of AEP Texas Central Company for Authority to Change Rates)*, Docket No. 38772, Order on Remand (Jan. 20, 2011).

[7] PFD at 26.

[8] *Id.* at 24-26.

B. FIN 48

The Financial Accounting Standards Board's Interpretation No. 48 (FIN 48) prescribes the way in which a company must analyze, quantify, and disclose the potential consequences of tax positions that the company has taken that are legally uncertain. Entergy reported that its uncertain tax positions totaled $5,916,461. FIN 48 requires that this amount be recorded on Entergy's balance sheet as a tax liability. Entergy also reported that it made a cash deposit with the IRS in the amount of $1,294,683 associated with its FIN 48 liability.[9]

The ALJs concluded that Entergy's FIN 48 liability should be included in its ADFIT balance, but the amount of the cash deposit made by Entergy to the IRS attributable to Entergy's FIN 48 liability should not be included in Entergy's ADFIT balance. Accordingly, the ALJs recommended that $4,621,778 (Entergy's FIN 48 liability of $5,916,461 less the $1,294,683 cash deposit Entergy has already made with the IRS) be added to Entergy's ADFIT balance and thus be used to offset Entergy's rate base.[10] The ALJs did not recommend the addition of a deferred-tax-account rider because no party expressly advocated the addition of such a rider.[11]

The Commission adopts the proposal for decision regarding the adjustment to Entergy's ADFIT for the amount attributable to Entergy's FIN 48 liability. However, the Commission also follows its precedent regarding the creation of a deferred-tax-account tracker and modifies the proposal for decision on this point. In CenterPoint's Electric Delivery Company's last rate case, Docket No. 38339,[12] the Commission found that tax schedule UTP—on which companies must describe, list, and rank each uncertain tax position—would provide the IRS auditors sufficient information to quickly determine which uncertain tax positions are of a magnitude worth investigating and that an IRS audit would be more likely to occur on some uncertain tax positions. If an IRS audit of a FIN 48 uncertain tax position results in an unfavorable outcome, the utility would not be able to earn a return on the amount paid to the IRS until the next rate case.

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[9] PFD at 26-27 (citing Rebuttal Testimony of Roberts, Entergy Ex. 64 at 6), 29 (citing Rebuttal Testimony of Roberts, Entergy Ex. 64 at 8).

[10] PFD at 29.

[11] *Id.* at 29.

[12] *Application of CenterPoint Electric Delivery Company, LLC for Authority to Change Rates*, Docket No. 38339, Order on Rehearing at 3-4 (June 23, 2011).

Accordingly, the Commission authorizes Entergy to establish a rider to track unfavorable FIN-48 rulings by the IRS. The rider will also allow Entergy to recover on a *prospective* basis an after-tax return of 8.27% on the amounts paid to the IRS that result from an unfavorable FIN-48 unfavorable-tax-position audit. The return will be applied prospectively to FIN-48 amounts disallowed by an IRS audit after such amounts are actually paid to the federal government. If Entergy subsequently prevails in an appeal of an unfavorable FIN-48 unfavorable-tax-position decision by the IRS, then any amounts collected under rider related to that overturned decision shall be credited back to ratepayers.

The Commission adds new finding of fact 40A and deletes finding of fact 41 consistent with its decision to authorize the deferred-tax-account tracker.

C. Capitalized Incentive Compensation

Entergy capitalized into plant-in-service accounts some of the incentive payments made to employees and sought to include those amounts in rate base. The ALJs determined that Entergy should not be able to recover its financially based incentive-compensation costs.[13] Therefore, the portion of Entergy's incentive-compensation costs capitalized during the period July 1, 2009 through June 30, 2010 that were financially based was excluded from Entergy's rate base. The ALJs also determined that the actual percentages should be used to determine the amount that is financially based.[14]

In discussing Entergy's incentive compensation as a component of operating expenses, the ALJs adopted the method advocated by Texas Industrial Energy Consumers (TIEC) for calculating the amount of the financially based incentive costs. This method uses the actual percentage reductions applicable to each of the annual incentive programs that included a component of financially-based costs.[15]

In its exceptions regarding capitalized incentive compensation, Entergy advocated for the use of TIEC's methodology to also calculate the amount of capitalized incentive compensation that is financially based. Entergy also noted that the amount of the disallowance reflected in the

[13] PFD at 171.

[14] *Id.* at 72.

[15] *Id.* at 174; *see also* Entergy's Exceptions to the Proposal for Decision at 25-26 (July 23, 2012).

schedules, $1,333,352, was calculated using a disallowance factor that included incentive compensation tied to cost-control measures, which the ALJs found to be recoverable in the operating-cost incentive-compensation calculation.[16] When the TIEC methodology is applied to the capitalized incentive-compensation costs in rate base, the net result under TIEC's methodology is that only $335,752.96 should be disallowed from capital costs.[17]

The Commission agrees that capitalized incentive compensation that is financially based should be excluded from rate base and that the exclusion only applies to incentive costs that Entergy capitalized during the period from July 1, 2009 through June 30, 2010. However, the Commission finds that a consistent methodology should be used to calculate the amount to be excluded and therefore that TIEC's methodology should also be used for calculating the amount of capitalized financially based incentive-compensation costs that should be excluded from rate base. Accordingly, the total amount of capitalized incentive-compensation costs that should be disallowed from rate base is $335,752.96. Finding of fact 61 is modified to reflect this determination.

As noted by Commission Staff, this disallowance to plant-in-service alters the expense for ad valorem taxes. Accounting for this disallowance, the appropriate expense amount for ad valorem taxes is $24,921,022,[18] an adjustment of $1,222,106 to Entergy's test year amount. Finding of fact 151 is modified to reflect this adjustment to property taxes.

D. Rate of Return and Cost of Capital

The ALJs found the proper range of an acceptable return on equity for Entergy would be from 9.3 percent to 10.0 percent.[19] The mid-point of the range is 9.65 percent. The ALJs found that the effect of unsettled economic conditions facing utilities on the appropriate return on equity should be taken into account and that the effect would be to move the ultimate return on equity towards the upper limits of the range that was determined to be reasonable.[20] The ALJs

[16] Entergy's Exceptions to the Proposal for Decision at 25-26.

[17] *Id.* at 25-26.

[18] Commission Number-Run Memorandum at 2 (Aug. 28, 2012).

[19] PFD at 94.

[20] *Id.*

found that the reasonable adjustment would be 15 basis points, moving the reasonable return on equity to 9.80 percent.[21]

The Commission must establish a reasonable return for a utility and must consider applicable factors.[22] The Commission disagrees with the ALJs that a utility's return on equity should be determined using an adder to reflect unsettled economic conditions facing utilities. The Commission agrees with the ALJs, however, that a return on equity of 9.80 percent will allow Entergy a reasonable opportunity to earn a reasonable return on its invested capital, but finds this rate appropriate independent of the 15-point adder recommended by the ALJs. A return on equity of 9.80 percent is within the range of an acceptable return on equity found by the ALJs. Accordingly, the Commission adds new finding of fact 65A to reflect the Commission's decision on this point.

E. Purchased-Power Capacity Expense

The ALJs rejected Entergy's request to recover $31 million more in purchased-power capacity costs than its actual test-year expenses because Entergy had failed to prove that the adjustment was known and measurable,[23] and because the request violated the matching principle.[24] Consequently, the ALJs recommended that Entergy's test-year expenses of $245,432,884 be used to set rates in this docket.[25]

Entergy pointed to an additional $533,002 of purchased-power capacity expenses that were properly included in Entergy's rate-filing package, but not provided for in the proposal for decision.[26] The Commission finds that an additional $533,002 ($6,132 for test-year expenses for Southwest Power Pool fees, $654,082 for Toledo Bend hydro fixed-charges, and -$127,212 for an Entergy intra-system billing adjustment that were all recorded in FERC account 555) of purchased-power capacity costs were incurred during the test-year and should be added to the purchased-power capacity costs in Entergy's revenue requirement. The Commission modifies

[21] *Id.* at 94.

[22] PURA §§ 36.051, .052.

[23] PFD at 108-09.

[24] *Id.* at 109.

[25] *Id.*

[26] Entergy's Exceptions to the Proposal for Decision at 51.

findings of fact 72 and 86 to reflect the inclusion of the additional $533,002 of test-year purchased-power capacity costs, increasing the total amount to $245,965,886.

F. Labor Costs – Incentive Compensation

The ALJs found that $6,196,037, representing Entergy's financially-based incentives paid in the test-year, should be removed from Entergy's O&M expenses.[27] The ALJs agreed with Commission Staff and Cities that an additional reduction should be made to account for the FICA taxes that Entergy would have paid for those costs,[28] but did not include this reduction in a finding of fact.

The Commission agrees with the ALJs, but modifies finding of fact 133 to specifically include the decision that an additional reduction should be made to account for the FICA taxes Entergy would have paid on the disallowed financially-based incentive compensation. The Commission notes that this reduction for FICA taxes is reflected in the schedules attached to this Order.[29]

G. Affiliate Transactions

OPUC argued that Entergy's sales and marketing expenses exclusively benefit the larger commercial and industrial customers, but the majority of the sales, marketing, and customer service expenses are allocated to the operating companies based on customer counts. Therefore, the majority of these expenses are allocated to residential and small business customers. OPUC argued that it is inappropriate for residential and small business customers to pay for these expenses.[30] The ALJs did not adopt OPUC's position on this issue.

The Commission agrees with OPUC and reverses the proposal for decision regarding allocation of Entergy's sales and marketing expense and finds that $2.086 million of sales and marketing expense should be reallocated using direct assignment. The Commission has

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[27] PFD at 175.

[28] *Id.* at 175-76.

[29] *See* Commission Number Run-Memorandum at 3 (Aug. 28, 2012).

[30] Direct Testimony of Carol Szerszen, OPUC Ex. 1 at 44-45.

previously expressed its preference for direct assignment of affiliate expenses.[31] The Commission finds that the following amounts should be allocated based on a total-number-of-customers basis: (1) $46,490 for Project E10PCR56224 – Sales and Marketing – EGSI Texas; (2) $17,013 for Project F3PCD10049 – Regulated Retail Systems O&M; and (3) $30,167 for Project F3PPMMALI2 – Middle Market Mkt. Development. The remainder, $1,992,475, should be assigned to (1) General Service, (2) Large General Service and (3) Large Industrial Power Service.[32] The reallocation has the effect of increasing the revenue requirement allocated to the large business class customers and reduces the revenue requirement for small business and residential customers. New finding of fact 164A is added to reflect the proper allocation of these affiliate transactions.

H. Fuel Reconciliation

Entergy proposed to allocate costs for the fuel reconciliation to customers using a line-loss study performed in 1997. Entergy conducted a line-loss study for the year ending December 31, 2010, which falls in the middle of the two year fuel reconciliation period—July 2009 through June 2011—and therefore reflects the actual line losses experienced by the customer classes during the reconciliation period. Cities argued that the allocation of fuel costs incurred over the reconciliation period should reflect the current line-loss study performed by Entergy for this case and recommended approval on a going-forward basis. Fuel factors under P.U.C. SUBST. R. 25.237(a)(3) are temporary rates subject to revision in a reconciliation proceeding described in P.U.C. SUBST. R. 25.236. P.U.C. SUBST. R. 25.236(d)(2) defines the scope of a fuel reconciliation proceeding to include any issue related to the reasonableness of a utility's fuel expenses and whether the utility has over- or under-recovered its reasonable fuel expenses.[33] Cities calculated a $3,981,271 reduction to the Texas retail fuel expenses incurred over the reconciliation period using the current line-losses. The ALJs rejected Cities' proposed adjustment finding that the P.U.C. SUBST. R. 25.237(c)(2)(B) requires the use of Commission-

[31] *Application of Central Power and Light Company for Authority to Change Rates*, Docket No. 14965, Second Order on Rehearing at 87, COL 29 (Oct. 16, 1997).

[32] Direct Testimony of Carol Szerszen, OPUC Ex. 1 at Schedule CAS-7.

[33] Cities' Exceptions to the Proposal for Decision at 20-21 (July 23, 2012).

approved line losses that were in effect at the time fuel costs were billed to customers in a fuel reconciliation.[34]

The Commission agrees with Cities and reverses the proposal for decision regarding which line-loss factors should be used in Entergy's fuel reconciliation. Entergy used the 2010 study line-loss calculations to calculate the demand- and energy-related allocations in its cost of service analysis supporting its requested base rates. These same currently available line-loss factors should have been utilized in Entergy's fuel reconciliation. The Commission finds that Entergy's 2010 line-loss factors should be used to calculate Entergy's fuel reconciliation over-recovery. As a result, Entergy's fuel reconciliation over-recovery should be reduced by $3,981,271. Finding of fact 246A and conclusions of law 19A and 19B are added to reflect the Commission's finding that the 2010 line-loss factors be used to reconcile Entergy's fuel costs.

I. MISO Transition Expenses

During the Commission's consideration of the proposal for decision, the parties that contested the amount of Entergy's MISO transition expenses and how the transition expenses should be accounted for reached announced on the record that they had reached an agreement on these issues.[35] Those parties agreed that the MISO transition expenses would not be deferred and that Entergy's base rates should include $1.6 million for MISO transition expense.[36] The Commission adopts the agreement of the parties and accordingly modifies finding of fact 251 and deletes finding of fact 252.

J. Purchased-Power Capacity Cost Baseline

The Commission modified the amount of purchased-power capacity expense in the test-year to be $245,965,886 (see section E above). Finding of fact 255 is modified to reflect the change to the proper test-year purchased-power capacity expense.

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[34] PFD at 327-328.

[35] Open Meeting Tr. at 138 (Aug. 17, 2012).

[36] *Id.*

K. Other Issues

New findings of fact 17A, 17B, 17C, 17D, and 17 E are added to reflect procedural aspects of the case after issuance of the proposal for decision.

In addition, to reflect corrections recommended by the ALJs, findings of fact 116, 123, 192, 194, and 202 are modified; and new finding of fact 182A is added.

The Commission adopts the following findings of fact and conclusions of law:

II. Findings of Fact

Procedural History

1. Entergy Texas, Inc. (ETI or the company) is an investor-owned electric utility with a retail service area located in southeastern Texas.

2. ETI serves retail and wholesale electric customers in Texas. As of June 30, 2011, ETI served approximately 412,000 Texas retail customers. The Federal Energy Regulatory Commission (FERC) regulates ETI's wholesale electric operations.

3. On November 28, 2011, ETI filed an application requesting approval of: (1) a proposed increase in annual base rate revenues of approximately $111.8 million over adjusted test-year revenues; (2) a set of proposed tariff schedules presented in the Electric Utility Rate Filing Package for Generating Utilities (RFP) accompanying ETI's application and including new riders for recovery of costs related to purchased-power capacity and renewable energy credit requirements; (3) a request for final reconciliation of ETI's fuel and purchased-power costs for the reconciliation period from July 1, 2009 to June 30, 2011; and (4) certain waivers to the instructions in RFP Schedule V accompanying ETI's application.

4. The 12-month test-year employed in ETI's filing ended on June 30, 2011 (test-year).

5. ETI provided notice by publication for four consecutive weeks before the effective date of the proposed rate change in newspapers having general circulation in each county of ETI's Texas service territory. ETI also mailed notice of its proposed rate change to all of

its customers. Additionally, ETI timely served notice of its statement of intent to change rates on all municipalities retaining original jurisdiction over its rates and services.

6. The following parties were granted intervenor status in this docket: Office of Public Utility Counsel; the cities of Anahuac, Beaumont, Bridge City, Cleveland, Conroe, Dayton, Groves, Houston, Huntsville, Montgomery, Navasota, Nederland, Oak Ridge North, Orange, Pine Forest, Rose City, Pinehurst, Port Arthur, Port Neches, Shenandoah, Silsbee, Sour Lake, Splendora, Vidor, and West Orange (Cities), the Kroger Co. (Kroger); State Agencies; Texas Industrial Energy Consumers; East Texas Electric Cooperative, Inc.; the United States Department of Energy (DOE); and Wal-Mart Stores Texas, LLC, and Sam's East, Inc. (Wal-Mart). The Staff (Staff) of the Public Utility Commission of Texas (Commission or PUC) was also a participant in this docket.

7. On November 29, 2011, the Commission referred this case to the State Office of Administrative Hearings (SOAH).

8. On December 7, 2011, the Commission issued its order requesting briefing on threshold legal/policy issues.

9. On December 19, 2011, the Commission issued its Preliminary Order, identifying 31 issues to be addressed in this proceeding.

10. On December 20, 2011, the Administrative Law Judges (ALJs) issued SOAH Order No. 2, which approved an agreement among the parties to establish a June 30, 2012 effective date for the company's new rates resulting from this case pursuant to certain agreed language and consolidate *Application of Entergy Texas, Inc. for Authority to Defer Expenses Related to its Proposed Transition to Membership in the Midwest Independent System Operator*, Docket No. 39741 (pending) into this proceeding. Although it did not agree, Staff did not oppose the consolidation.

11. On January 13, 2012, the ALJs issued SOAH Order No. 4 granting the motions for admission pro hac vice filed by Kurt J. Boehm and Jody M. Kyler to appear and participate as counsel for Kroger and the motion for admission *pro hac vice* filed by Rick D. Chamberlain to appear and participate as counsel for Wal-Mart.

12. On January 19, 2012, the Commission issued a supplemental preliminary order identifying two additional issues to be addressed in this case and concluding that the company's proposed purchased-power capacity rider should not be addressed in this case and that such costs should be recovered through base rates.

13. ETI timely filed with the Commission petitions for review of the rate ordinances of the municipalities exercising original jurisdiction within its service territory. All such appeals were consolidated for determination in this proceeding.

14. On April 4, 2012, the ALJs issued SOAH Order No. 13 severing rate case expense issues into *Application of Entergy Texas, Inc. for Rate Case Expenses Severed from PUC Docket No. 39896*, Docket No. 40295 (pending).

15. On April 13, 2012, ETI adjusted its request for a proposed increase in annual base rate revenues to approximately $104.8 million over adjusted test-year revenues.

16. The hearing on the merits commenced on April 24 and concluded on May 4, 2012.

17. Initial post-hearing briefs were filed on May 18 and reply briefs were filed on May 30, 2012.

17A. On August 7, 2012, the SOAH ALJs filed a letter with the Commission recommending changes to the PFD.

17B At the July 27, 2012 open meeting, ETI agreed to extend the effective date of rates to August 31, 2012 to provide the Commission sufficient time to consider the issues in this proceeding.

17C. The Commission considered the proposal for decision at the August 17, 2012 and August 30, 2012 open meetings.

17D. At the August 30, 2012 open meeting, ETI agreed to extend the effective date of rates to September 14, 2012.

17E. At the August 17, 2012 open meeting, parties announced on the record a settlement of the amount of costs for the transition to MISO.

Rate Base

18. Capital additions that were closed to ETI's plant-in-service between July 1, 2009 and June 30, 2011, are used and useful in providing service to the public and were prudently incurred.

19. ETI's proposed Hurricane Rita regulatory asset was an issue resolved by the black-box settlement in *Application of Entergy Texas, Inc. for Authority to Change Rates and Reconcile Fuel Costs*, Docket No. 37744 (Dec. 13, 2010).

20. Accrual of carrying charges on the Hurricane Rita regulatory asset should have ceased when Docket No. 37744 concluded because the asset would have then begun earning a rate of return as part of rate base.

21. The appropriate calculation of the Hurricane Rita regulatory asset should begin with the amount claimed by ETI in Docket No. 37744, less amortization accruals to the end of the test-year in the present case, and less the amount of additional insurance proceeds received by ETI after the conclusion of Docket No. 37744.

22. A Test-Year-end balance of $15,175,563 for the Hurricane Rita regulatory asset should remain in rate base, applying a five-year amortization rate beginning August 15, 2010.

23. The Hurricane Rita regulatory asset should not be moved to the storm damage insurance reserve.

24. The company requested in rate base its prepaid pension assets balance of $55,973,545, which represents the accumulated difference between the Statement of Financial Accounting Standards (SFAS) No. 87 calculated pension costs each year and the actual contributions made by the company to the pension fund.

25. The prepaid pension assets balance includes $25,311,236 capitalized to construction work in progress (CWIP).

26. It is not necessary to the financial integrity of ETI to include CWIP in rate base, and there was insufficient evidence showing that major projects under construction were efficiently and prudently managed.

27. The portion of the prepaid pension assets balance that is capitalized to CWIP should not be included in ETI's rate base.

28. The remainder of the prepaid pension assets balance should be included in ETI's rate base.

28A. When items are excluded from rate base, the related ADFIT should also be excluded. The amount of ADFIT associated with the $25 million capitalized to CWIP and excluded from rate base is $8,858,933. The adjusted ADFIT for the prepaid pension asset remaining in Entergy's rate base should be reduced by $8,858,933.

29. ETI should be permitted to accrue an allowance for funds used during construction on the portion of ETI's Prepaid Pension Assets Balance capitalized to CWIP.

30. The Financial Accounting Standard Board (FASB) Financial Interpretation No. 48 (FIN 48), "Accounting for Uncertainty in Income Taxes," requires ETI to identify each of its uncertain tax positions by evaluating the tax position on its technical merits to determine whether the position, and the corresponding deduction, is more-likely-than-not to be sustained by the Internal Revenue Service (IRS) if audited.

31. FIN 48 requires ETI to remove the amount of its uncertain tax positions from its Accumulated Deferred Federal Income Tax (ADFIT) balance for financial reporting purposes and record it as a potential liability with interest to better reflect the company's financial condition.

32. At test-year-end, ETI had $5,916,461 in FIN 48 liabilities, meaning ETI has, thus far, avoided paying to the IRS $5,916,461 in tax dollars (the FIN 48 liability) in reliance upon tax positions that the company believes will not prevail in the event the positions are challenged, via an audit, by the IRS.

33. ETI has deposited $1,294,683 with the IRS in connection with the FIN 48 liability.

34. The IRS may never audit ETI as to its uncertain tax positions creating the FIN 48 liability.

35. Even if ETI is audited, ETI might prevail on its uncertain tax positions.

36. ETI may never have to pay the IRS the FIN 48 liability.

37. Other than the amount of its deposit with the IRS, ETI has current use of the FIN 48 liability funds.

38. Until actually paid to the IRS, the FIN 48 liability represents cost-free capital and should be deducted from rate base.

39. The amount of $4,621,778 (representing ETI's full FIN 48 liability of $5,916,461 less the $1,294,683 cash deposit ETI has made with the IRS for the FIN 48 liability) should be added to ETI's ADFIT and thus be used to reduce ETI's rate base.

40. ETI's application and proposed tariffs do not include a request for a tracking mechanism or rider to collect a return on the FIN 48 liability.

40A. It is appropriate for ETI to create a deferred-tax-account tracker in the form of a rider to recover on a prospective basis an after-tax return of 8.27% on the amounts paid to the IRS that result from an unfavorable FIN 48 audit. The rider will track unfavorable FIN 48 rulings and the return will be applied prospectively to FIN 48 amounts disallowed by an IRS audit after such amounts are actually paid to the federal government. If ETI prevails in an appeal of a FIN 48 decision, then any amounts collected under the rider related to that decision should be credited back to ratepayers.

41. Deleted.

42. Investor-owned electric utilities may include a reasonable allowance for cash working capital in rate base as determined by a lead-lag study conducted in accordance with the Commission's rules.

43. Cash working capital represents the amount of working capital, not specifically addressed in other rate base items, that is necessary to fund the gap between the time expenditures are made and the time corresponding revenues are received.

44. The lead-lag study conducted by ETI considered the actual operations of ETI, adjusted for known and measurable changes, and is consistent with P.U.C. SUBST. R. 25.231(c)(2)(B)(iii).

45. It is reasonable to establish ETI's cash working capital requirement based on ETI's lead-lag study as updated in Jay Joyce's rebuttal testimony and on the cost of service approved for ETI in this case.

46. As a result of the black-box settlements in *Application of Entergy Gulf States, Inc. for Authority to Change Rates and to Reconcile Fuel Costs*, Docket No. 34800 (Nov. 7, 2008) and Docket No. 37744, the Commission did not approve ETI's storm damage expenses since 1996 and its storm damage reserve balance.

47. ETI established a prima facie case concerning the prudence of its storm damage expenses incurred since 1996.

48. Adjustments to the storm damage reserve balance proposed by intervenors should be denied.

49. The Hurricane Rita regulatory asset should not be moved to the storm damage insurance reserve.

50. ETI's appropriate Test-Year-end storm reserve balance was negative $59,799,744.

51. The amount of $9,846,037, representing the value of the average coal inventory maintained at ETI's coal-burning facilities, is reasonable, necessary, and should be included in rate base.

52. The Spindletop gas storage facility (Spindletop facility) is used and useful in providing reliable and flexible natural gas supplies to ETI's Sabine Station and Lewis Creek generating plants.

53. The Spindletop facility is critical to the economic, reliable operation of the Sabine Station and Lewis Creek generating plants due to their geographic location in the far western region of the Entergy system.

54. It is reasonable and appropriate to include ETI's share of the costs to operate the Spindletop facility in rate base.

55. Staff recommended updating ETI's balance amounts for short-term assets to the 13-month period ending December 2011, which was the most recent information available.

Staff's proposed adjustments should be incorporated into the calculation of ETI's rate base.

56. The following short-term asset amounts should be included in rate base: prepayments at \$8,134,351; materials and supplies at \$29,285,421; and fuel inventory at \$52,693,485.

57. The amount of \$1,127,778, representing costs incurred by ETI when it acquired the Spindletop facility, represent actual costs incurred to process and close the acquisition, not mere mark-up costs.

58. ETI's \$1,127,778 in capitalized acquisition costs should be included in rate base because ETI incurred these costs in conjunction with the purchase of a viable asset that benefits its retail customers.

59. In its application, ETI capitalized into plant in service accounts some of the incentive payments ETI made to its employees. ETI seeks to include those amounts in rate base.

60. A portion of those capitalized incentive accounts represent payments made by ETI for incentive compensation tied to financial goals.

61. The portion of ETI's incentive payments that are capitalized and that are financially-based should be excluded from ETI's rate base because the benefits of such payments inure most immediately and predominantly to ETI's shareholders, rather than its electric customers. ETI's capitalized incentive compensation that is financially based is \$335,752.96 and should be removed for rate base.

62. The test-year for ETI's prior ratemaking proceeding ended on June 30, 2009, and the reasonableness of ETI's capital costs (including capitalized incentive compensation) for that prior period was dealt with by the Commission in that proceeding and is not at issue in this proceeding.

63. In this proceeding, ETI's capitalized incentive compensation that is financially-based should be excluded from rate base, but only for incentive costs that ETI capitalized during the period from July 1, 2009 (the end of the prior test-year) through June 30, 2010 (the commencement of the current test-year).

Rate of Return and Cost of Capital

64. A return on common equity (ROE) of 9.80 percent will allow ETI a reasonable opportunity to earn a reasonable return on its invested capital.

65. The results of the discounted cash flow model and risk premium approach support a ROE of 9.80 percent.

65A. It is not appropriate to add 15 points to the ROE due to unsettled economic conditions facing utilities.

66. A 9.80 percent ROE is consistent with ETI's business and regulatory risk.

67. ETI's proposed 6.74 percent embedded cost of debt is reasonable.

68. The appropriate capital structure for ETI is 50.08 percent long-term debt and 49.92 percent common equity.

69. A capital structure composed of 50.08 percent debt and 49.92 percent equity is reasonable in light of ETI's business and regulatory risks.

70. A capital structure composed of 50.08 percent debt and 49.92 percent equity will help ETI attract capital from investors.

71. ETI's overall rate of return should be set as follows:

COMPONENT	CAPITAL STRUCTURE	COST OF CAPITAL	WEIGHTED AVG COST OF CAPITAL
LONG-TERM DEBT	50.08%	6.74%	3.38%
COMMON EQUITY	49.92%	9.80%	4.89%
TOTAL	100.00%		8.27%

Operating Expenses

72. ETI's test-year purchased capacity expenses were $245,965,886.

73. ETI requested an upward adjustment of $30,809,355 as a post-test-year adjustment to its purchased capacity costs. This request was based on ETI's projections of its purchased capacity expenses during a period beginning June 1, 2012 and ending May 31, 2013 (the rate-year).

74. ETI's purchased capacity expense projections were based on estimates of rate-year expenses for: (a) reserve equalization payments under Schedule MSS-1; (b) payments under third-party capacity contracts; and (c) payments under affiliate contracts.

75. ETI's projection of its rate-year reserve equalization payments under Schedule MSS-1 is based on numerous assumptions, including load growths for ETI and its affiliates, future capacity contracts for ETI and its affiliates, and future values of the generation assets of ETI and its affiliates.

76. There is substantial uncertainty with regard to ETI's projection of its rate-year reserve equalization payments under Schedule MSS-1.

77. ETI's projection of its rate-year third-party capacity contract payments includes numerous assumptions, one of which is that every single third-party supplier will perform at the maximum level under the contract, even though that assumption is inconsistent with ETI's historical experience.

78. There is substantial uncertainty with regard to ETI's projection of its rate-year third-party capacity-contract payments.

79. ETI's estimates of its rate-year purchases under affiliate contracts are based on a mathematical formula set out in Schedule MSS-4.

80. The MSS-4 formula for rate-year affiliate capacity payments reflects that these payments will be based on ratios and costs that cannot be determined until the month that the payments are to be made.

81. Over $11 million of ETI's affiliate transactions were based on a 2013 contract (the EAI WBL Contract) that was not signed until April 11, 2012.

82. There is uncertainty about whether the EAI WBL Contract will ever go into effect.

83. ETI projects purchasing over 300 megawatts (MW) more in purchased capacity in the rate-year than it purchased in the test-year.

84. ETI experienced substantial load growth in the two years before the test-year, and it continues to project similar load growth in the future.

85. ETI did not meet its burden of proof to demonstrate that a known and measurable adjustment of $30,809,355 should be made to its test-year purchased capacity expenses.

86. ETI's purchased capacity expense in this case should be based on the test-year level of $245,965,886.

87. ETI incurred $1,753,797 of transmission equalization expense during the test-year.

88. ETI proposed an upward adjustment of $8,942,785 for its transmission equalization expense. This request was based on ETI's projections of its transmission equalization expenses during the rate-year.

89. The transmission equalization expense that ETI will pay in the rate-year will depend on future costs and loads for each of the Entergy operating companies.

90. ETI's projection of its rate-year transmission equalization expenses is uncertain and speculative because it depends on a number of variables, including future transmission investments, deferred taxes, depreciation reserves, costs of capital, tax rates, operating expenses, and loads of each of the Entergy operating companies.

91. ETI seeks increased transmission equalization expenses for transmission projects that are not currently used and useful in providing electric service. ETI's post-test-year adjustment is based on the assumption that certain planned transmission projects will go into service after the test-year. At the close of the hearing, none of the planned transmission projects had been fully completed and some were still in the planning phase.

92. It is not reasonable for ETI to charge its retail ratepayers for transmission equalization expenses related to projects that are not yet in-service.

93. ETI's request for a post-test-year adjustment of $8,942,785 for rate-year transmission equalization expenses should be denied because those expenses are not known and measurable. ETI's post-test-year adjustment does not with reasonable certainty reflect what ETI's transmission equalization expense will be when rates are in effect.

94. ETI's transmission equalization expense in this case should be based on the test-year level of $1,753,797.

95. P.U.C. SUBST. R. 25.231(c)(2)(ii) states that the reserve for depreciation is the accumulation of recognized allocations of original cost, representing the recovery of initial investment over the estimated useful life of the asset.

96. Except in the case of the amortization of the general plant deficiency, the use of the remaining life depreciation method to recover differences between theoretical and actual depreciation reserves is the most appropriate method and should be continued.

97. It is reasonable for ETI to calculate depreciation reserve allocations on a straight-line basis over the remaining, expected useful life of the item or facility.

98. Except as described below, the service lives and net salvage rates proposed by the company are reasonable, and these service lives and net salvage rates should be used in calculating depreciation rates for the company's production, transmission, distribution, and general plant assets.

99. A 60-year life for Sabine Units 4 and 5 is reasonable for purposes of establishing production plant depreciation rates.

100. The retirement (actuarial) rate method, rather than the interim retirement method, should be used in the development of production plant depreciation rates.

101. Production plant net salvage is reasonably based on the negative five percent net salvage in existing rates.

102. The net salvage rate of negative 10 percent for ETI's transmission structures and improvements (FERC Account 352) is the most reasonable of those proposed and should be adopted.

103. The net salvage rate of negative 20 percent for ETI's transmission station equipment (FERC Account 353) is the most reasonable of those proposed and should be adopted.

104. The net salvage rate of negative five percent for ETI's transmission towers and fixtures (FERC Account 354) is the most reasonable of those proposed and should be adopted.

105. The net salvage rate of negative 30 percent for ETI's transmission poles and fixtures (FERC Account 355) is the most reasonable of those proposed and should be adopted.

106. The net salvage rate of negative 30 percent for ETI's transmission overhead conductors and devices (FERC Account 356) is the most reasonable of those proposed and should be adopted.

107. A service life of 65 years and a dispersion curve of R3 for ETI's distribution structures and improvements (FERC Account 361) are the most reasonable of those proposed and should be approved.

108. A service life of 40 years and a dispersion curve of R1 for ETI's distribution poles, towers, and fixtures (FERC Account 364) are the most reasonable of those proposed and should be approved.

109. A service life of 39 years and a dispersion curve of R0.5 for ETI's distribution overhead conductors and devices (FERC Account 365) are the most reasonable of those proposed and should be approved.

110. A service life of 35 years and a dispersion curve of R1.5 for ETI's distribution underground conductors and devices (FERC Account 367) are the most reasonable of those proposed and should be approved.

111. A service life of 33 years and a dispersion curve of L0.5 for ETI's distribution line transformers (FERC Account 368) are the most reasonable of those proposed and should be approved.

112. A service life of 26 years and a dispersion curve of L4 for ETI's distribution overhead service (FERC Account 369.1) are the most reasonable of those proposed and should be approved.

113. The net salvage rate of negative five percent for ETI's distribution structures and improvements (FERC Account 361) is the most reasonable of those proposed and should be adopted.

114. The net salvage rate of negative 10 percent for ETI's distribution station equipment (FERC Account 362) is the most reasonable of those proposed and should be adopted.

115. The net salvage rate of negative seven percent for ETI's distribution overhead conductors and devices (FERC Account 365) is the most reasonable of those proposed and should be adopted.

116. The net salvage rate of positive five percent for ETI's distribution line transformers (FERC Account 368) is the most reasonable of those proposed and should be adopted.

117. The net salvage rate of negative 10 percent for ETI's distribution overhead services (FERC Account 369.1) is the most reasonable of those proposed and should be adopted.

118. The net salvage rate of negative 10 percent for ETI's distribution underground services (FERC Account 369.2) is the most reasonable of those proposed and should be adopted.

119. A service life of 45 years and a dispersion curve of R2 for ETI's general structures and improvements (FERC Account 390) are the most reasonable of those proposed and should be approved.

120. The net salvage rate of negative 10 percent for ETI's general structures and improvements (FERC Account 390) is the most reasonable of those proposed and should be adopted.

121. It is reasonable to convert the $21.3 million deficit that has developed over time in the reserve for general plant accounts to General Plant Amortization.

122. A ten-year amortization of the deficit in the reserve for general plant accounts is reasonable and should be adopted.

123. FERC pronouncement AR-15 requires amortization over the same life as recommended based on standard life analysis. A standard life analysis determined that a five-year life was appropriate for general plant computer equipment (FERC Account 391.2). Therefore, a five year amortization for this account is reasonable and should be adopted.

124. ETI proposed adjustments to its test-year payroll costs to reflect: (a) changes to employee headcount levels at ETI and Entergy Services, Inc. (ESI); and (b) approved wage increases set to go into effect after the end of the test-year.

125. The proposed payroll adjustments are reasonable but should be updated to reflect the most recent available information on headcount levels as proposed by Commission Staff.

In addition to adjusting payroll expense levels, the more recent headcount numbers should be used to adjust the level of payroll tax expense, benefits expense, and savings plan expense.

126. Staff has appropriately updated headcount levels to the most recent available data but errors made by Staff should be corrected. The corrections related to: (a) a double counting of three ETI and one ESI employee; (b) inadvertent use of the ETI benefits cost percentage in the calculation of ESI benefits costs; (c) an inappropriate reduction of savings plan costs when such costs were already included in the benefits percentage adjustments; and (d) corrections for full-time equivalents calculations. Staff's ETI headcount adjustment (AG-7) overstated operation and maintenance (O&M) payroll reduction by $224,217, and ESI headcount adjustment (AG-7) understated O&M payroll increase by $37,531.

127. ETI included $14,187,744 for incentive compensation expenses in its cost of service.

128. The compensation packages that ETI offers its employees include a base payroll amount, annual incentive programs, and long-term incentive programs. The majority of the compensation is for operational measures, but some is for financial measures.

129. Incentive compensation that is based on financial measures is of more immediate and predominant benefit to shareholders, whereas incentive compensation based on operational measures is of more immediate and predominant benefit to ratepayers.

130. Incentives to achieve operational measures are necessary and reasonable to provide utility services but those to achieve financial measures are not.

131. The $5,376,975 that was paid for long term incentive programs was tied to financial measures and, therefore, should not be included in ETI's cost of service.

132. Of the amounts that were paid pursuant to the Executive Annual Incentive Plan, $819,062 was tied to financial measures and, therefore, should be disallowed.

133. In total, the amount of incentive compensation that should be disallowed is $6,196,037 because it was related to financial measures that are not reasonable and necessary for the provision of electric service. An additional reduction should be made to account for the

FICA taxes ETI would have paid on the disallowed financially based incentive compensation.

134. The amount of incentive compensation that should be included in the cost of service is $7,991,707.

135. To attract and retain highly qualified employees, the Entergy companies provide a total package of compensation and benefits that is equivalent in scope and cost with what other comparable companies within the utility business and other industries provide for their employees.

136. When using a benchmark analysis to compare companies' levels of compensation, it is reasonable to view the market level of compensation as a range rather than a precise, single point.

137. ETI's base pay levels are at market.

138. ETI's benefits plan levels are within a reasonable range of market levels.

139. ETI's level of compensation and benefits expense is reasonable and necessary.

140. ETI provides non-qualified supplemental executive retirement plans for highly compensated individuals such as key managerial employees and executives that, because of limitations imposed under the Internal Revenue Code, would otherwise not receive retirement benefits on their annual compensation over $245,000 per year.

141. ETI's non-qualified supplemental executive retirement plans are discretionary costs designed to attract, retain, and reward highly compensated employees whose interests are more closely aligned with those of the shareholders than the customers.

142. ETI's non-qualified executive retirement benefits in the amount of $2,114,931 are not reasonable or necessary to provide utility service to the public, not in the public interest, and should not be included in ETI's cost of service.

143. For the employee market in which ETI operates, most peer companies offer moving assistance. Such assistance is expected by employees, and ETI would be placed at a competitive disadvantage if it did not offer relocation expenses.

144. ETI's relocation expenses were reasonable and necessary.

145. The company's requested operating expenses should be reduced by $40,620 to reflect the removal of certain executive prerequisites proposed by Staff.

146. Staff properly adjusted the company's requested interest expense of $68,985 by removing $25,938 from FERC account 431 (using the interest rate of 0.12 percent for calendar year 2012), leaving a recommended interest expense of $43,047.

147. During the test-year, ETI's property tax expense equaled $23,708,829.

148. ETI requested an upward *pro forma* adjustment of $2,592,420, to account for the property tax expenses ETI estimates it will pay in the rate-year.

149. ETI's requested *pro forma* adjustment is not reasonable because it is based, in part, upon the prediction that ETI's property tax rate will be increased in 2012, a change that is speculative is not known and measurable.

150. Staff's recommendation to increase ETI's test-year property tax expenses by $1,214,688 is based on the historical effective tax rate applied to the known test-year-end plant in service value, consistent with Commission precedent, and based upon known and measurable changes.

151. ETI's test-year property tax burden should be adjusted upward by $1,222,106 for a total expense of $24,921,022.

152. Staff recommended reducing ETI's advertising, dues, and contributions expenses by $12,800. The recommendation, which no party contested, should be adopted.

153. The final cost of service should reflect changes to cost of service that affect other components of the revenue requirement such as the calculation of the Texas state gross receipts tax, the local gross receipts tax, the PUC Assessment Tax and the Uncollectible Expenses.

154. The company's requested Federal income tax expense is reasonable and necessary.

155. ETI's request for $2,019,000 to be included in its cost of service to account for the company's annual decommissioning expenses associated with River Bend is not

reasonable because it is not based upon "the most current information reasonably available regarding the cost of decommissioning" as required by P.U.C. SUBST. R. 25.231(b)(1)(F)(i).

156. Based on the most current information reasonably available, the appropriate level of decommissioning costs to be included in ETI's cost of service is $1,126,000.

157. ETI's appropriate total annual self-insurance storm damage reserve expense is $8,270,000, comprised of an annual accrual of $4,400,000 to provide for average annual expected storm losses, plus an annual accrual of $3,870,000 for 20 years to restore the reserve from its current deficit.

158. ETI's appropriate target self-insurance storm damage reserve is $17,595,000.

159. ETI should continue recording its annual storm damage reserve accrual until modified by a Commission order.

160. The operating costs of the Spindletop facility are reasonable and necessary.

161. The operating costs of the Spindletop facility paid to PB Energy Storage Services are eligible fuel expenses.

Affiliate Transactions

162. ETI affiliates charged ETI $78,998,777 for services during the test-year. The majority of these O&M expenses—$69,098,041—were charged to ETI by ESI. The remaining affiliate services were charged (or credited) to ETI by: Entergy Gulf States Louisiana, L.L.C.; Entergy Arkansas, Inc.; Entergy Louisiana, LLC; Entergy Mississippi, Inc.; Entergy Operations, Inc.; and non-regulated affiliates.

163. ESI follows a number of processes to ensure that affiliate charges are reasonable and necessary and that ETI and its affiliates are charged the same rate for similar services. These processes include: (a) the use of service agreements to define the level of service required and the cost of those services; (b) direct billing of affiliate expenses where possible; (c) reasonable allocation methodologies for costs that cannot be directly billed; (d) budgeting processes and controls to provide budgeted costs that are reasonable and

necessary to ensure appropriate levels of service to its customers; and (e) oversight controls by ETI's Affiliate Accounting and Allocations Department.

164. Affiliates charged expenses to ETI through 1292 project codes during the test-year.

164A. The $2,086,145 in affiliate transactions related to sales and marketing expenses should be reallocated using direct assignment. The following amounts should be allocated to all retail classes in proportion to number of customers: (1) $46,490 for Project E10PCR56224 – Sales and Marketing – EGSI Texas; (2) $17,013 for Project F3PCD10049 – Regulated Retail Systems O&M; and (3) $30,167 for Project F3PPMMALI2 – Middle Market Mkt. Development. The remainder, $1,992,475, should be assigned to (1) General Service, (2) Large General Service and (3) Large Industrial Power Service.

165. ETI agreed to remove the following affiliate transactions from its application: (1) Project F3PPCASHCT (Contractual Alternative/Cashpo) in the amount of $2,553; (2) Project F3PCSPETEI (Entergy-Tulane Energy Institute) in the amount of $14,288; and (3) Project F5PPKATRPT (Storm Cost Processing & Review) in the amount of $929.

166. The $356,151 (which figure includes the $112,531 agreed to by ETI) of costs associated with Projects F5PCZUBENQ (Non-Qualified Post Retirement) and F5PPZNQBDU (Non Qual Pension/Benf Dom Utl) are costs that are not reasonable and necessary for the provision of electric utility service and are not in the public interest.

167. The $10,279 of costs associated with Project F3PPFXERSP (Evaluated Receipts Settlement) are not normally-recurring costs and should not be recoverable.

168. The $19,714 of costs associated with Project F3PPEASTIN (Willard Eastin et al) are related to ESI's operations, it is more immediately related to Entergy Louisiana, Inc. and Entergy New Orleans, Inc. As such, they are not recoverable from Texas ratepayers.

169. The $171,032 of costs associated with Project F3PPE9981S (Integrated Energy Management for ESI) are research and development costs related to energy efficiency programs. As such, they should be recovered through the energy efficiency cost recovery factor rather than base rates.

170. Except as noted in the above findings of fact Nos. 162-169, all remaining affiliate transactions were reasonable and necessary, were allowable, were charged to ETI at a price no higher than was charged by the supplying affiliate to other affiliates, and the rate charged is a reasonable approximation of the cost of providing service.

Jurisdictional Cost Allocation

171. ETI has one full or partial requirements wholesale customer – East Texas Electric Cooperative, Inc.

172. ETI proposes that 150 MW be set as the wholesale load for developing retail rates in this docket. Using 150 MW to set the wholesale load is reasonable. The 150 MW used to set the wholesale load results in a retail production demand allocation factor of 95.3838 percent.

173. The 12 Coincident Peak (12 CP) allocation method is consistent with the approach used by the FERC to allocate between jurisdictions.

174. Using 12CP methodology to allocate production costs between the wholesale and retail jurisdictions is the best method to reflect cost responsibility and is appropriate based on ETI's reliance on capacity purchases.

Class Cost Allocation and Rate Design

175. There is no express statutory authorization for ETI's proposed Renewable Energy Credits rider (REC rider).

176. REC rider constitutes improper piecemeal ratemaking and should be rejected.

177. ETI's test-year expense for renewable energy credits, $623,303, is reasonable and necessary and should be included in base rates.

178. Municipal Franchise Fees (MFF) is a rental expense paid by utilities for the right to use public rights-of-way to locate its facilities within municipal limits.

179. ETI is an integrated utility system. ETI's facilities located within municipal limits benefit all customers, whether the customers are located inside or outside of the municipal limits.

180. Because all customers benefit from ETI's rental of municipal right-of-way, municipal franchise fees should be charged to all customers in ETI's service area, regardless of geographic location.

181. It is reasonable and consistent with the Public Utility Regulatory Act (PURA) § 33.008(b) that MFF be allocated to each customer class on the basis of in-city kilowatt hour (kWh) sales, without an adjustment for the MFF rate in the municipality in which a given kWh sale occurred.

182. The same reasons for allocating and collecting MFF as set out in Finding of Fact Nos. 178-181 also apply to the allocation and collection of Miscellaneous Gross Receipts Taxes. The company's proposed allocation of these costs to all retail customer classes based on customer class revenues relative to total revenues is appropriate.

182A. ETI's proposed gross plant-based allocator is an appropriate method for allocating the Texas franchise tax.

183. The Average and Excess (A&E) 4CP method for allocating capacity-related production costs, including reserve equalization payments, to the retail classes is a standard methodology and the most reasonable methodology.

184. The A&E 4CP method for allocating transmission costs to the retail classes is standard and the most reasonable methodology.

185. ETI appropriately followed the rate class revenue requirements from its cost of service study to allocate costs among customer classes. ETI's revenue allocation properly sets rates at each class's cost of service.

186. It is reasonable for ETI to eliminate the service condition for Rate Groups A and C in Schedule SHL [Street and Highway Lighting Service] that charges a $50 fee for any replacement of a functioning light with a lower-wattage bulb.

187. It is appropriate to require ETI to prepare and file, as part of its next base rate case, a study regarding the feasibility of instituting LED-based rates and, if the study shows that such rates are feasible, ETI should file proposals for LED-based lighting and traffic signal rates in its next rate case.

188. An agreement was reached by the parties and approved by the Commission in Docket No. 37744 that directed ETI to exclude, in its next rate case, the life-of-contract demand ratchet for existing customers in the Large Industrial Power Service (LIPS), Large Industrial Power Service-Time of Day, General Service, General Service-Time of Day, Large General Service, and Large General Service-Time of Day rate schedules.

189. ETI's proposed tariffs in this case did not remove the life-of-contract demand ratchet from these rate schedules consistent with the parties' agreement in Docket No. 37744.

190. A perpetual billing obligation based on a life-of-contract demand ratchet, as ETI proposed, is not reasonable.

191. ETI's proposed LIPS and LIPS Time of Day tariffs should be modified to reflect the agreement that was adopted by the Commission as just and reasonable in Docket No. 37744. Accordingly, these tariffs should be modified as set out in Findings of Fact No. 192-194.

192. ETI's Schedule LIPS and LIPS Time of Day § VI should be changed to read:

DETERMINATION OF BILLING LOAD

The kW of Billing Load will be the greatest of the following:

(A) The Customer's maximum measured 30-minute demand during any 30-minute interval of the current billing month, subject to §§ III, IV and V above; or

(B) 75% of Contract Power as defined in § VII; or

(C) 2,500 kW.

193. ETI's Schedule LIPS and LIPS Time of Day § VII should be changed to read:

DETERMINATION OF CONTRACT POWER

Unless Company gives customer written notice to the contrary, Contract Power will be defined as below:

Contract Power - the highest load established under § VI(A) above during the 12 months ending with the current month. For the initial 12 months of Customer's service under the currently effective contract, the Contract Power shall be the kW specified in the currently effective contract unless exceeded in any month during the initial 12-month period.

194. The Large General Service, Large General Service-Time of Day, General Service, and General Service-Time of Day schedules should be similarly revised to eliminate ETI's life-of-contract demand ratchet.

195. In its proposed rate design for the LIPS class, the company took a conservative approach and increased the current rates by an equal percentage. This minimized customer bill impacts while maintaining cost causation principles on a rate class basis.

196. It is a reasonable move towards cost of service to add a customer charge of $630 to the LIPS rate schedule with subsequent increases to be considered in subsequent base rate cases.

197. It is a reasonable move towards cost of service to slightly decrease the LIPS energy charges and increase the demand charges as proposed by Staff witness William B. Abbott.

198. DOE proposed a new Schedule LIPS rider—Schedule "Schedulable Intermittent Pumping Service" (SIPS) for load schedulable at least four weeks in advance, that occurs in the off-season (November through April), that can be cancelled at any time, and for load not lasting more than 80 hours in a year. For customers whose loads match these SIPS characteristics (for example, DOE's Strategic Petroleum Reserve), the 12-month demand ratchet provision of Schedule LIPS does not apply to demands set under the provisions of the SIPS rider. The monthly demand set under the SIPS provisions would be applicable for billing purposes only in the month in which it occurred. In short, if a customer set a 12-month ratchet demand in that month, it would be forgiven and not applicable in the succeeding 12 months.

199. DOE's proposed Schedule SIPS is not restricted solely to the DOE and should be adopted. It more closely addresses specific customer characteristics and provides for cost-based rates, as does another ETI rider applicable to Pipeline Pumping Service.

200. Standby Maintenance Service (SMS) is available to customers who have their own generation equipment and who contract for this service from ETI.

201. P.U.C. SUBST. R. 25.242(k)(1) provides that rates for sales of standby and maintenance power to qualifying facilities should recognize system wide costing principles and should not be discriminatory.

202. It is reasonable to move Schedule SMS toward cost of service by: (a) adding a customer charge equivalent to that of the LIPS rate schedule only for SMS customers not purchasing supplementary power under another applicable rate; and (b) revising the tariff as follows:

Charge	Distribution (less than 69KV)	Transmission (69KV and greater)
Billing Load Charge ($/kW):		
Standby	$2.46	$0.79
Maintenance	$2.27	$0.60
Non-Fuel Energy Charge (¢/kWh)		
On-Peak	4.245¢	4.074¢
Off-Peak	0.575¢	0.552¢

203. ETI's Additional Facilities Charge rider (Schedule AFC) prescribes the monthly rental charge paid by a customer when ETI installs facilities for that customer that would not normally be supplied, such as line extensions, transformers, or dual feeds.

204. ETI existing Schedule AFC provides two pricing options. Option A is a monthly charge. Option B, which applies when a customer elects to amortize the directly-assigned facilities over a shorter term ranging from one to ten years, has a variable monthly charge. There is also a term charge that applies after the facility has been fully depreciated.

205. It is reasonable and cost-based to reduce the Schedule AFC Option A rate to 1.20 percent per month of the installed cost of all facilities included in the agreement for additional facilities.

206. It is reasonable and cost-based to reduce the Schedule AFC Option B monthly rate and the Post Term Recovery Charge as follows:

Selected Recovery Term	Recovery Term Charge	Post Recovery Term Charge
1	10.88%	0.35%
2	5.39%	0.35%
3	3.92%	0.35%
4	3.20%	0.35%
5	2.76%	0.35%
6	2.48%	0.35%
7	2.28%	0.35%
8	2.14%	0.35%
9	1.97%	0.35%
10	1.94%	0.35%

207. The revisions in the above findings of fact to Schedule AFC rates reasonably reflect the costs of running, operating, and maintaining the directly-assigned facilities.

208. It is reasonable to modify the Large General Service rate schedule by increasing the demand charge from $10.25 to $12.81; decreasing the energy charge from $.01023 to $.00513; and maintaining the customer charge at $425.05.

209. Staff's proposed change to the General Service (GS) rate schedule to gradually move GS customers towards their cost of service by recommending a decrease in the customer charge from the current rate of $41.09 to $39.91, and a decrease in the energy charges is reasonable and should be adopted.

210. ETI's Residential Service (RS) rate schedule is composed of two elements: a customer charge of $5 per month and a consumption-based energy charge. The Energy charge is a fixed rate of 5.802¢ per kWh from May through October (summer). In the months November through April (winter), the rates are structured as a declining block, in which the price of each unit is reduced after a defined level of usage.

211. ETI's Schedule RS declining block rate structure is contrary to energy-efficiency efforts and the Legislature's goal of reducing both energy demand and energy consumption in Texas, as stated in PURA § 39.905.

212. Schedule RS winter block rates should be modified consistent with the goal set out in PURA § 39.905, with the initial phase-in of a 20 percent reduction in the block differential proposed by ETI and subsequent reductions should be reviewed for consideration at the occurrence of each rate case filing.

213. Other elements of Schedule RS are just and reasonable.

Fuel Reconciliation

214. ETI incurred $616,248,686 in natural-gas expenses during the reconciliation period, which is from July 2009 through June 2011.

215. ETI purchased natural gas in the monthly and daily markets and pursuant to a long-term contract with Enbridge Inc. pipeline. ETI also transported gas on its own account and negotiated operational balancing agreements with various pipeline companies.

216. ETI employed a diversified portfolio of gas supply and transportation agreements to meet its natural-gas requirements, and ETI prudently managed its gas-supply contracts.

217. ETI's natural gas expenses were reasonable and necessary expenses incurred to provide reliable electric service to retail customers.

218. ETI incurred $90,821,317 in coal expenses during the reconciliation period.

219. ETI prudently managed its coal and coal-related contracts during the reconciliation period.

220. ETI monitored and audited coal invoices from Louisiana Generating, LLC for coal burned at the Big Cajun II, Unit 3 facility.

221. ETI's coal expenses were reasonable and necessary expenses incurred to provide reliable electric service to retail customers.

222. ETI incurred $990,041,434 in purchased-energy expenses during the reconciliation period.

223. The Entergy System's planning and procurement processes for purchased-power produced a reasonable mix of purchased resources at a reasonable price.

224. During the reconciliation period, ETI took advantage of opportunities in the fuel and purchased-power markets to reduce costs and to mitigate against price volatility.

225. ETI's purchased-energy expenses were reasonable and necessary expenses incurred to provide reliable electric service to retail customers.

226. ETI provided sufficient contemporaneous documentation to support the reasonableness of its purchased-power planning and procurement processes and its actual power purchases during the reconciliation period.

227. The Entergy system sold power off system when the revenues were expected to be more than the incremental cost of supplying generation for the sale, subject to maintaining adequate reserves.

228. The System Agreement is the tariff approved by the FERC that provides the basis for the operation and planning of the Entergy system, including the six operating companies. The System Agreement governs the wholesale-power transactions among the operating companies by providing for joint operation and establishing the bases for equalization among the operating companies, including the costs associated with the construction, ownership, and operation of the Entergy system facilities.

229. Under the terms of the Entergy System Agreement, ETI was allocated its share of revenues and expenses from off-system sales.

230. During the reconciliation period, ETI recorded off-system sales revenue in the amount of $376,671,969 in FERC Account 447 and credited 100 percent of off-system sales revenues and margins from off-system sales to eligible fuel expenses.

231. ETI properly recorded revenues from off-system sales and credited those revenues to eligible fuel costs.

232. The Entergy system consists of six operating companies, including ETI, which are planned and operated as a single, integrated electric system under the terms of the System Agreement.

233. Service schedule MSS-1 of the System Agreement determines how the capability and ownership costs of reserves for the Entergy system are equalized among the operating

companies. These inter-system "reserve equalization" payments are the result of a formula rate related to the Entergy system's reserve capability that is applied on a monthly basis.

234. Reserve capability under service schedule MSS-1 is capability in excess of the Entergy system's actual or planned load built or acquired to ensure the reliable, efficient operation of the electric system.

235. By approving service schedule MSS-1, the FERC has approved the method by which the operating companies share the cost of maintaining sufficient reserves to provide reliability for the Entergy system as a whole.

236. Service schedule MSS-3 of the System Agreement determines the pricing and exchange of energy among the operating companies. By approving service schedule MSS-3, the FERC has approved the method by which the operating companies are reimbursed for energy sold to the exchange energy pool and how that energy is purchased.

237. Service schedule MSS-4 of the System Agreement sets forth the method for determining the payment for unit power purchases between operating companies. By approving service schedule MSS-4, the FERC has approved the methodology for pricing inter-operating company unit power purchases.

238. The Entergy system is planned using multi-year, annual, seasonal, monthly, and next-day horizons. Once the planning process has identified the most economical resources that can be used to reliably meet the aggregate Entergy system demand, the next step is to procure the fuel necessary to operate the generating units as planned and acquire wholesale power from the market.

239. Once resources are procured to meet forecasted load, the Entergy system is operated during the current day using all the resources available to meet the total Entergy system demand.

240. After current-day operation, the System Agreement prescribes an accounting protocol to bill the costs of operating the system to the individual operating companies. This protocol is implemented via the intra-system bill to each operating company on a monthly basis.

241. ETI purchased power from affiliated operating companies per the terms of service schedule MSS-3 of the System Agreement. The payments made under Schedule MSS-3 to affiliated operating companies are reasonable and necessary, and the FERC has approved the pricing formula and the obligation to purchase the energy. ETI pays the same price per megawatt hour for energy under service schedule MSS-3 as does any other operating company purchasing energy under service schedule MSS-3 during the same hour.

242. The Spindletop facility is used primarily to ensure gas-supply reliability and guard against gas-supply curtailments that can occur as a result of extreme weather or other unusual events.

243. The Spindletop facility provides a secondary benefit of flexibility in gas supply. ETI can back down gas-fired generation to take advantage of more economical wholesale power, or use gas from storage to supplement gas-fired generation when load increases during the day and thereby avoid more expensive intra-day gas purchases.

244. ETI's customers received benefits from the Spindletop facility during the reconciliation period through reliable gas supplies and ETI's monthly and daily storage activity.

245. ETI prudently managed the Spindletop facility to provide reliability and flexibility of gas supply for the benefit of customers.

246. ETI proposed new loss factors, based on a December 2010 line-loss study, to be applied for the purpose of allocating its costs to its wholesale customers and retail customer classes.

246A. ETI's 2010 line-loss factors should be used to reconcile ETI's fuel costs. Therefore, ETI's fuel reconciliation over-recovery should be reduced by $3,981,271.

247. ETI's proposed loss factors are reasonable and shall be implemented on a prospective basis as a result of this final order.

248. ETI seeks a special-circumstances exception to recover $99,715 resulting from the FERC's reallocation of rough production equalization costs in FERC Order No. 720-A, and to treat such costs as eligible fuel expense.

249. Special circumstances exist and it is appropriate for ETI to recover the rough production cost equalization costs reallocated to ETI as a result of the FERC's decision in Order No. 720-A.

Other Issues

250. A deferred accounting of ETI's Midwest Independent Transmission System Operator (MISO) transition expenses is not necessary to carry out any requirement of PURA.

251. ETI should include $1.6 million in base rates for MISO transition expense.

252. Deleted.

253. Transmission Cost Recovery Factor baseline values should be set during the compliance phase of this docket, after the Commission makes final rulings on the various contested issues that may affect this calculation.

254. Distribution Cost Recovery Factor baseline values should be set during the compliance phase of this docket, after the Commission makes final rulings on the various contested issues that may affect this calculation.

255. The appropriate amount for ETI's purchased-power capacity expense to be included in base rates is $245,965,886.

256. The amount of ETI's purchased-power capacity expense includes third-party contracts, legacy affiliate contracts, other affiliate contracts, and reserve equalization. Whether the amounts for all contracts should be included in the baseline for a purchased-capacity rider that may be approved in Project No. 39246 is an issue that should be decided in that project.

III. Conclusions of Law

1. ETI is a "public utility" as that term is defined in PURA § 11.004(1) and an "electric utility" as that term is defined in PURA § 31.002(6).

2. The Commission exercises regulatory authority over ETI and jurisdiction over the subject matter of this application pursuant to PURA §§ 14.001, 32.001, 32.101, 33.002, 33.051, 36.101–.111, and 36.203.

3. SOAH has jurisdiction over matters related to the conduct of the hearing and the preparation of a proposal for decision in this docket, pursuant to PURA § 14.053 and TEX. GOV'T CODE ANN. § 2003.049.

4. This docket was processed in accordance with the requirements of PURA and the Texas Administrative Procedure Act, Tex. Gov't Code Ann. Chapter 2001.

5. ETI provided notice of its application in compliance with PURA § 36.103, P.U.C. PROC. R. 22.51(a), and P.U.C. SUBST. R. 25.235(b)(1)-(3).

6. Pursuant to PURA § 33.001, each municipality in ETI's service area that has not ceded jurisdiction to the Commission has jurisdiction over the company's application, which seeks to change rates for distribution services within each municipality.

7. Pursuant to PURA § 33.051, the Commission has jurisdiction over an appeal from a municipality's rate proceeding.

8. ETI has the burden of proving that the rate change it is requesting is just and reasonable pursuant to PURA § 36.006.

9. In compliance with PURA § 36.051, ETI's overall revenues approved in this proceeding permit ETI a reasonable opportunity to earn a reasonable return on its invested capital used and useful in providing service to the public in excess of its reasonable and necessary operating expenses.

10. Consistent with PURA § 36.053, the rates approved in this proceeding are based on original cost, less depreciation, of property used and useful to ETI in providing service.

11. The ADFIT adjustments approved in this proceeding are consistent with PURA § 36.059 and P.U.C. SUBST. R. 25.231(c)(2)(C)(i).

12. Including the cash working capital approved in this proceeding in ETI's rate base is consistent with P.U.C. SUBST. R. 25.231(c)(2)(B)(iii)(IV), which allows a reasonable allowance for cash working capital to be included in rate base.

13. The ROE and overall rate of return authorized in this proceeding are consistent with the requirements of PURA §§ 36.051 and 36.052.

14. The affiliate expenses approved in this proceeding and included in ETI's rates meet the affiliate payment standards articulated in PURA §§ 36.051, 36.058, and *Railroad Commission of Texas v. Rio Grande Valley Gas Co.*, 683 S.W.2d 783 (Tex. App.—Austin 1984, no writ).

15. The ADFIT adjustments approved in this proceeding are consistent with PURA § 36.059 and P.U.C. SUBST. R. 25.231(c)(2)(C)(i).

16. Pursuant to P.U.C. SUBST. R. 25.231(b)(1)(F), the decommissioning expense approved in this case is based on the most current information reasonably available regarding the cost of decommissioning, the balance of funds in the decommissioning trust, anticipated escalation rates, the anticipated return on the funds in the decommissioning trust, and other relevant factors.

17. ETI has demonstrated that its eligible fuel expenses during the reconciliation period were reasonable and necessary expenses incurred to provide reliable electric service to retail customers as required by P.U.C. SUBST. R. 25.236(d)(1)(A). ETI has properly accounted for the amount of fuel-related revenues collected pursuant to the fuel factor during the reconciliation period as required by P.U.C. SUBST. R. 25.236(d)(1)(C).

18. ETI prudently managed the dispatch, operations, and maintenance of its fossil plants during the reconciliation period.

19. The reconciliation period level operating and maintenance expenses for the Spindletop facility are eligible fuel expenses pursuant to P.U.C. SUBST. R. 25.236(a).

19A. Fuel factors under P.U.C. SUBST. R. 25.237(a)(3) are temporary rates subject to revision in a reconciliation proceeding.

19B. P.U.C. SUBST. R. 25.236(d)(2) defines the scope of a fuel reconciliation proceeding to include any issue related to the reasonableness of a utility's fuel expenses and whether the utility has over- or under-recovered its reasonable fuel expenses. It is proper to use the new line-loss study to calculate Entergy's fuel reconciliation and over-recovery.

20. Special circumstances are warranted pursuant to P.U.C. SUBST. R. 25.236(a)(6) to recover rough production equalization payments reallocated to ETI by the FERC.

21. ETI's rates, as approved in this proceeding, are just and reasonable in accordance with PURA § 36.003.

IV. Ordering Paragraphs

In accordance with these findings of fact and conclusions of law, the Commission issues the following orders:

1. The proposal for decision prepared by the SOAH ALJs is adopted to the extent consistent with this Order.
2. ETI's application is granted to the extent consistent with this Order.
3. ETI shall file in Tariff Control No. 40742 *Compliance Tariff Pursuant to Final Order in Docket No. 39896 (Application of Entergy Texas, Inc. for Authority to Change Rates, Reconcile Fuel Costs, and Obtain Deferred Accounting Treatment)* tariffs consistent with this Order within 20 days of the date of this Order. No later than ten days after the date of the tariff filings, Staff shall file its comments recommending approval, modification, or rejection of the individual sheets of the tariff proposal. Responses to the Staff's recommendation shall be filed no later than 15 days after the filing of the tariff. The Commission shall by letter approve, modify, or reject each tariff sheet, effective the date of the letter.
4. The tariff sheets shall be deemed approved and shall become effective on the expiration of 20 days from the date of filing, in the absence of written notification of modification or rejection by the Commission. If any sheets are modified or rejected, ETI shall file proposed revisions of those sheets in accordance with the Commission's letter within ten days of the date of that letter, and the review procedure set out above shall apply to the revised sheets.
5. Copies of all tariff-related filings shall be served on all parties of record.
6. ETI shall prepare and file as part of its next base rate case a study regarding the feasibility of instituting LED-based rates and, if the study shows that such rates are feasible, ETI should file proposals for LED-based lighting and traffic signal rates in that case. If ETI has LED lighting customers taking service, the study shall include detailed

information regarding differences in the cost of serving LED and non-LED lighting customers. ETI shall provide the results of this study to Cities and interested parties as soon as practicable, but no later than the filing of its next rate case.

7. All other motions, requests for entry of specific findings of fact and conclusions of law, and any other requests for general or specific relief, if not expressly granted, are denied.

SIGNED AT AUSTIN, TEXAS the 14th day of September 2012.

PUBLIC UTILITY COMMISSION OF TEXAS

DONNA L. NELSON, CHAIRMAN

ROLANDO PABLOS, COMMISSIONER

I respectfully dissent regarding the utility- and executive-management-class affiliate transactions. To be consistent with Commission precedent in Docket No. 14965,[37] the indirect costs of the management of Entergy's ultimate parent should not be borne by Texas ratepayers. Therefore, I would disallow the following: $173,867 for Project No. F3PCCPM001 (Corporate Performance Management); $372,919 for Project No. F3PCC31255 (Operations-Office of the CEO); and $74,485 for Project No. F3PPCOO001 (Chief Operating Officer). I join the Commission in all other respects for this Order.

KENNETH W. ANDERSON, JR., COMMISSIONER

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[37] *Application of Central Power and Light Company for Authority to Change Rates*, Docket No. 14965, Second Order on Rehearing (Oct. 16, 1997).

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF DELAWARE

IN THE MATTER OF THE APPLICATION OF DELMARVA POWER & LIGHT COMPANY FOR AN INCREASE IN ELECTRIC BASE RATES AND MISCELLANEOUS TARIFF CHANGES (FILED March 22, 2013)	))))))	PSC DOCKET NO. 13-115

CERTIFICATE OF SERVICE

I hereby certify that on February 5, 2014, I caused the attached **POST HEARING REPLY BRIEF OF DELMARVA POWER & LIGHT COMPANY** to be served upon all parties on the attached service list via electronic mail.

Todd L. Goodman
Delmarva Power & Light Company
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Mail Stop 92 DC 42
Newark, DE 19702
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February 5, 2014

SERVICE LIST
DP&L ELECTRIC BASE RATE CASE
PSC DOCKET No. 13-115
As of 1/02/14

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